Assessing the Strategic Benefits of Distributed Generation Ownership for DNOs

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Pierluigi Siano[1], Luis F. Ochoa[2], Gareth P. Harrison[3], and Antonio Piccolo[4]

[1] Department of Information & Electrical Engineering
University of Salerno, Fisciano, Italy
e-mail: psiano@unisa.it
[2] Institute for Energy Systems, School of Engineering and Electronics
University of Edinburgh, Edinburgh, EH9 3JL, UK
e-mail: luis_ochoa@ieee.org
[3] Institute for Energy Systems, School of Engineering and Electronics
University of Edinburgh, Edinburgh, EH9 3JL, UK
e-mail: gareth.harrison@ed.ac.uk
[4] Department of Information & Electrical Engineering
University of Salerno, Fisciano, Italy
e-mail: apiccolo@unisa.it

Abstract

The potential for distributed generation (DG) to act as an alternative distribution planning option is now well-recognised by academia and industry, and could play a significant role in electricity distribution utility operation and design. However, the unbundling requirements of European Directive 2003/54/EC, coupled with traditional network planning approaches adopted by European Distribution Network Operators (DNOs), appear to be hindering development of DG and its deployment for distribution network ancillary services. This paper examines the incentives – or otherwise – that arise from alternative models of DG ownership by bundled and unbundled distribution utilities. The preference for the siting and sizing of DG installations by DNOs is simulated using a multi-year multi-period optimal power flow. Broadly based on the recent UK regulatory framework, this paper explores the DG ownership issue and its potential to influence DG penetration.

Index Terms

Distributed generation, incentives, unbundling, optimal power flow, power generation planning.

1. Introduction

In order to meet load growth and provide customers with a reliable electricity supply, Distribution Network Operators (DNOs) traditionally design networks with sufficient levels of redundancy to support most eventualities and by considering the expansion or reinforcement of existing circuits. Studies have indicated the potential of distributed generation (DG) in offering a range of solutions for distribution network security, planning and management issues, while maintaining the cost-effectiveness. The benefits include loss reduction, energy savings, peak shaving, voltage control, ancillary services, higher power quality, lower loss of load probability as well as deferral of transmission and distribution replacement [1]-[7]. An additional point of particular relevance for transmission and distribution networks which are reaching the end of their design life, is that there is an opportunity to redesign integrated networks that recognise and facilitate the contribution of DG rather than performing like-for-like replacement of aged network assets.

To enable DG to become an effective option for DNO planning and compete with traditional network solutions, it is critical that a level playing field with proper integration of DG into distribution networks is created. However, the commercial and regulatory frameworks to facilitate this appear not to be in place in many countries. Specifically, the issue of prohibition of DNO ownership of DG – a key part of unbundling – requires further examination.

This paper assesses the current European regulations on DG ownership in terms of its impact on network operators' incentives for enhancing DG penetration. It builds on earlier work [8]-[10] that showed that the contrasting incentives that DG presented to developers and DNOs had a significant impact on their respective preference for DG penetration. Sections 2 and 3, respectively consider current regulations on ownership and the incentives presented to DNOs in connecting DG. Section 4, presents a multi-year multi-period Optimal Power Flow (OPF) approach to examine the preferences of DNOs in terms of where they would choose to site DG given the incentives that arise from allowing ownership or otherwise. Sections 5 and 6 present and discuss a case study as to whether ownership helps or hinders DNO connection of DG. Finally, conclusions are drawn in Section 7.

2. Legislative Framework on DG Ownership

2.1. European Regulation

European Directive 2003/54/EC [11] defines the technical and legal boundaries that must exist between the different market actors within European electricity and gas markets. Specifically it establishes the unbundling rules, according to which DNOs must be unbundled from generation interests, thus in effect prohibiting DNOs from owning generation plants. It also separates the physical distribution of electricity from retail supply in which distribution utilities are not involved in selling power to consumers. Several European electricity markets were fully unbundled prior to the Directive, notably the UK. The unbundling process is designed to avoid cross-subsidies as well as a level playing field in the competitive areas of the market specifically to avoid (say) a DNO favouring a generation business owned by the same parent company. Unless there are explicit exemptions in place that relate to particular Member States, DNOs are not allowed to own generation plants in European States. This is the case in the UK except for a small number of legacy diesel plant used specifically as backup for subsea connections between remote islands and the mainland.

While the separation of transmission and generation can reduce inefficiencies associated with monopoly operation, the lack of integration between network and generation planning can potentially lead to inefficiencies in electricity supply infrastructure than the equivalent system where generation is integrated within grid network planning [12]. With this clearly in mind, European Directives 2005/89/EC [13], as well as Directive 2003/54/EC, imply that DNOs should consider the installation of DG for planning the expansion of the distribution network. However, they do not specify how this should be implemented without a degree of coordination between the distribution network planners and the generation companies whilst respecting unbundling requirements. Furthermore, it has been argued [14], [15] that prohibition of DG ownership is leading DNOs to overlook DG in favour of infrastructure investments resulting in the operational benefits of DG being disregarded to the disadvantage of optimal system operation. Anecdotal evidence suggests this is the case in the UK [16].

2.2. Regulation in the USA

To some extent the US approach to DG ownership is driven by the more traditional structure of distribution utilities in which they remain responsible for supplying customers through purchasing power from a range of sources in addition to owning and operating the wires. The economic benefits of installed DG to the utility from deferred generation and distribution investments are well recognised [17] and utilities are allowed to situate DG at strategic locations on the grid in order to defer network upgrade costs and reduce peak-hour supply expenses [18]. Additionally, distribution companies may offer capacity payments for units that can be dispatched during times of system need in order to ensure availability and to address their interests in performance guarantees.

In California, investor-owned electric utilities are required to consider non-utility owned distributed resources as alternatives to distribution system investments. Utility-owned DG is therefore permitted and utilities should evaluate when DG is a viable distribution alternative to enhance reliability, safety and cost [19]. Network operators should also inform DG developers of specific locations where DG represents a potential distribution alternative and pay DG providers who defer distribution upgrades.

The New York Public Service Commission incorporated DG technologies in the utility distribution system planning process. Customer-owned DG proposals are evaluated against traditional system improvement projects and distribution system needs are satisfied on a least cost basis developing case-specific information on DG costs and benefits, considering a range of distribution system conditions.

3. DG, Ownership and Incentives

Non-utility developers are typically driven by the availability of resources (e.g., wind, gas) in dictating the location and capacity of DG. In addition, DG developers – particularly in the private sector – are likely to require higher rates of return than the regulated rates applicable to the DNO (typically around 7% in the UK). A scheme that offers a poor return for a developer may well be financially viable to the DNO, particularly when compared to network upgrades. However, it may be in the DNO's – and by extension customers' – interest for a DG to be developed at a strategically important location that would otherwise not attract interest from a non-utility developer.

For DNOs the drivers are more complex given the wide range of technical and economic issues that DG influences. These include:

- regulatory pressure to manage capital and operational expenditure;
- quality of supply and security standards;
- regulatory incentives on reliability (e.g. customer interruptions) and losses;
- charging structure or incentives for DG connection.

DNOs in the UK are regulated on the basis of 5-year distribution price controls in which capital and operational expenditure levels, rates-of-return and use-of-system charges are agreed with the regulator. These place considerable pressure on DNOs to minimise capital and operational expenditure. One particular area of note is the potential benefit of DG in deferring network reinforcement to ensure load is met. The benefit can be significant with a US study [20] suggesting marginal capacity benefits of up to US$1,795/kW which is broadly similar to the AUS$1,500/kW reported for parts of Sydney, Australia [21].

The primary impact of DG is on quality of supply, particularly voltage profiles and it is well known that statutory voltage limits can create a barrier for larger DG. DG can positively affect levels of security within networks by being able to substitute for network assets under predefined network outage conditions. In the UK, the planning standard Engineering Recommendation (ER) P2/6 now provides a basis for quantifying contribution to system security from DG units [22]. The DG security contribution value is heavily dependent on the reliance that can be placed on the DG to produce power at times of peak load.

Reliability is of critical importance in modern distribution and DNOs are expected to maintain or improve customer reliability. DG may significantly increase reliability provided that islanding operation is allowed and the corresponding protection and communication systems are in place [3]. Many DNOs are incentivised with regard to network losses. This may be through country-wide standardised loss levels, responsibility for loss purchasing or DNO-specific incentive schemes like those in the UK. Such a scheme was introduced in 2005 to encourage UK DNOs to manage losses effectively by rewarding loss reduction and penalizing increases relative to a DNO-specific target levels. The tendency for modest capacities of DG to reduce losses offers an incentive for DNOs to limit DG connections within their networks [8], [23].

There is significant diversity internationally in practices for connecting DG including use of both deep and shallow charging in the EU [24], [25], while in the US, a connection ‘allowance’ applies above which developers are charged costs [24]. There is limited use of Distribution Use of System (DUoS) charges for DG except in a few cases, including Sweden (DG>1.5 MW [26]) and the UK. Although UK DNOs are now developing cost-reflective locational DUoS for medium voltage DG, the DUoS charges introduced in the 2005 distribution price control [27] were notable for the use of an annual payment to the DNO per kW of DG capacity. This modest £2.50/kW contribution towards capital and operations costs was intended to incentivise the DNO to connect DG by providing an above-regulated rate of return [25].

3.1. Influence of ownership

Given these pressures, what additional incentives does ownership of DG provide for DNOs? The primary benefit is that it can choose where to place DG as well as controlling its operating pattern. This provides opportunities to capture the deferment benefit through peak load operation and potentially reduce losses through operation at other beneficial periods. While non-DG-owning DNOs can gain benefit from deferred reinforcement and losses from DG, it is as a by-product of developer decision-making as the DNO is not explicitly considering DG as an alternative to the network assets.

A further possible influence is that the DNO gains an additional revenue stream from the sale of electricity from the DG and an additional cost stream from the purchase of fuel. A key difference would be that the price of electricity and the fuel would vary over time. With electricity sales outside the DNO’s core expertise, it would seem likely that the DNO would seek to enter power purchase agreements with a Supplier (potentially within its own group) to sell the electricity and with fuel suppliers to procure fuel. The alternative of merchant sales would attract increased risk and a higher required rate-of-return than traditional network assets.

Where the purchasing Supplier is a subsidiary of the same parent company as the DNO there is an interesting question as to whether this might represent an opportunity for anti-competitive behaviour either on energy prices or in connection and charging processes. With regards to energy price gaming, in a market with fully competitive generation and supply businesses the options for group-level manipulation are perhaps limited as the Supplier would need to be purchasing power competitively and could not pay artifi-

cially high prices. On the connection side there could be concern over favourable treatment in terms of network 'intelligence' regarding suitable sites for connection [28], connection practices or connection/use-of-system charging. However, it is assumed that where formal separation of businesses is enforced and the connections process and charging is transparent and auditable then these risks can be minimised.

4. Modelling DNO Preferences

The effect of differing ownership rules and the associated incentives these create for DNOs can be demonstrated by considering where and in what capacities a DNO would choose to place DG to maximise its own benefit. Assuming that DNOs will aim to maximise their benefits, two alternative regulatory cases are considered:

1. DG-Owning DNO – allowed to own DG and can exploit the economic benefits brought about by considering new generation as an alternative to distribution system investments;
2. Unbundled DNO – prohibited from DG ownership but can maximise benefits based on a narrower set of incentives.

In assessing the effect of incentives on preferences, this work builds on earlier analysis [8]. It employed optimal capacity allocation to determine the locational and capacity preferences of developers and DNOs by defining the optimal capacity of new generation that may be accommodated within the existing network, subject to a range of constraints imposed by statute (e.g., voltage limits) or equipment specification (e.g., thermal limits on transformers and lines). By constraining the optimisation within existing technical limits the cost of network reinforcement that otherwise would be required to connect larger DG can be avoided by DNOs. This is a reasonable assumption for the DNO as its business is not to export as much power as possible.

The assessment method uses a bespoke multi-year multi-period optimal power flow developed to determine optimal DG capacity over a given planning horizon. Based on the OPF methods of [29] and [30] as extended by [8], the addition of a multi-year optimisation captures the planning process more realistically including the impact of investment timing as well as load growth. The computational burden is managed by the use of discrete load bands across each year (maximum, normal work hour, medium and minimum load, Fig. 1) which change as the load grows over the planning period.

4.1. DNO Objectives

The incentives given to DNOs to encourage DG connection will vary from system to system. Here, the arrangements generally applicable to the UK are used to illustrate the analysis, although the principles should apply to other liberalised systems.

In being able to place generation where it chooses the DNO can select the size of DG that provides the greatest benefit. In building a DG the DNO would incur upfront capital expenditure followed by annual operating costs including fuel, and operations and maintenance (O&M). DNOs would, however, benefit from not upgrading the network and sales of electricity. Broadly, these are both a function of DG capacity. In systems like the UK where DG pays the DNO DUoS, a DG-owning DNO would effectively pay itself so there is no direct connection incentive payable. While the analysis does not include the benefits associated with network security and reliability impacts of DG they are considered to be feasible to include within the same framework.

With the addition of penalties/rewards for losses, the net benefit to the DNO over the planning horizon from owning and siting its own DG can be described as an objective function:

$$OF_1 = \sum_{y=1}^{N} \frac{R_y + LI_y - OM_y}{(1+d)^y} + (ND - CDG) \cdot P_{DG} \,. \tag{1}$$

Here all annual values are discounted at the rate d; R_y is annual energy sales (£/year) in year y; OM_y is annual operations and maintenance and fuel costs (£/year); P_{DG} is the total DG capacity connected (kW); and N is the planning horizon (years). Two components, CDG, the capital cost of DG and ND, the network deferral benefit (both £/kW of DG) are not discounted: with connection at the start of the period CDG is already at present value while ND is the present value of the deferral benefit and therefore does not require additional discounting. The annual loss incentive LI_y (£/year)

$$LI_y = CLoss_y (TLoss_y - ALoss_y) \tag{2}$$

which values losses at $CLoss_y$ (£/MWh) and rewards or penalises actual annual losses ($ALoss_y$, MWh) relative to the pre-specified target level ($TLoss_y$, MWh).

The deferment model inherited from [8] assumes a very simple case where specified network elements

have been identified as requiring reinforcement to cope with demand growth. Importantly, the benefit that arises from connecting a DG is considered as independent of its location within the network, i.e., all DG capacity contributes equally. An example of this would be where transformers at grid supply sub-stations are approaching capacity and, without DG contributing to peak load, would otherwise require upgrading. With the DG units assumed to provide a firm supply, the benefit applies to the entire DG capacity.

The unbundled DNO would have a far simpler set of incentives. By not being able to own DG, the DNO does not formally recognise the network deferral benefits. However, its preferences for DG location can still be defined by the incentives offered by the loss targets as well as connection payments. These can be described by:

$$OF_2 = \sum_{y=1}^{N} \frac{1}{(1+d)^y} \left[CI_y \cdot P_{DG} + LI_y \right] \tag{3}$$

where CI_y is the payment the DNO receives for every kW of DG capacity connected (£/kW/year) and LI_y the loss incentive defined earlier.

4.2. DG Representation and Network Constraints

It is assumed that the DG offers a firm (non-intermittent) supply of energy and operates for a defined number of hours at rated capacity. The individual DG capacity p_g at a given location may be limited by the energy resource available:

$$p_g \le p_g^{\max}. \tag{4}$$

While distributed voltage control or active management allows larger DG capacities to connect by flexibly controlling reactive power (q_g) [23], [31], most DG currently operates at fixed power factors:

$$\cos\phi_g = p_g \Big/ \sqrt{p_g^2 + q_g^2} = const. \tag{5}$$

To date, only the major network constraints on DG capacity of voltage, thermal and fault level constraints have been incorporated within the OPF formulation. Voltage step change, stability, protection or other operational or planning constraints could also be considered as required. For simplicity, voltage and thermal constraints are considered here which is acceptable for voltage-dominated rural systems.

Quality of supply standards require voltages to be maintained close to nominal:

$$V_b^{\min} \le V_b \le V_b^{\max} \tag{6}$$

where $V_b^{\min}$ and $V_b^{\max}$ are the lower and upper bounds of the bus voltage V_b. The thermal capacity $S_t^{\max}$ of circuit t also limits the maximum apparent power transfer, S_t:

$$\left|S_t\right| \le S_t^{\max}. \tag{7}$$

The full mathematical specification of the multi-year multi-period OPF applied here is presented in the Appendix. The method was implemented in Matlab® by adapting the OPF component of the MATPOWER suite [32] to a multi-period approach. To validate the results it was also coded in the AIMMS optimisation modelling environment [33] in a similar manner to the paper formulation in the Appendix. The non-linear programming solver CONOPT was employed. Their use is illustrated in the following case study.

5. Case Study

5.1. 69-bus Network

The technique was applied to a 69-bus 11 kV radial distribution system [34]. The four feeders are supplied by a 6 MVA 33/11 kV transformer (in compliance with the UK security of supply regulations [22]). Voltage limits are taken to be ±6% of nominal and feeder thermal limits are 5.1 MVA (270 A/phase). The complete network data are given in [34].

The loading at each bus is assumed to follow the load curve in Fig. 1. The maximum three-phase load levels for each bus are given in [34]. These values were scaled down at the base year, and the corresponding loading levels for each band are given in Table 1. The mean aggregate network load is just under 2.2 MW. In order for the circuit to maintain the voltages within the established limits, voltage at the substation was set initially (no DG) to 1.02pu. The corresponding levels of losses in each band for the base year are also given in Table 1. The weighted average power loss is 51 kW (around 2.4% of average consumption).

The network one-line diagram is shown in Fig. 2. Voltage values for some end nodes, and the capacity utilisation of the line sections in the top of each feeder, are also presented.

Fig. 3 shows a yearly analysis of the network during peak load considering a growth of 3% and a plan-

ning horizon of 15 years. It can be verified that while the conductors exhibit considerable extra headroom for further demand, it is not that case for the 6 MVA transformer. Indeed, before year 10, new investments would be needed for the substation to cope with power flows. As for the voltages, varying the tap settings along the planning horizon allows values to be kept within the specified limits.

5.2. Regulatory frameworks and DG Capacity

In order to compare the benefits brought about by the DG-owning and unbundled DNO regulatory cases, seven potential DG locations (buses 5, 13, 27, 35, 40, 57 and 65) were defined. This was to avoid the trivial case of a DG being connected at the substation secondary bus and allows examination of impact of DG on voltage profiles, losses, etc. The DG was assumed to be connected (if at all) at the start of the planning period. DG units are assumed to have fixed power factors of 0.9 lagging (producing reactive power). Voltage at the substation will be set to nominal (1.00pu) throughout the planning horizon.

A real discount rate d of 9% is applied to all cash flows. Two alternative DG investments are considered: high capital cost-low operational cost natural gas engines and low capital cost high operational cost diesel gensets. The gas engines have an investment cost of £600/kW with operation and maintenance costs, including fuel costs, of £28/MWh [1]. The diesel gensets have low installation costs of around £100/kW but much higher fuel and operational costs at around £150/MWh [16]. The revenues deriving from electricity sales have been assumed to be £47/MWh which is broadly in line with wholesale prices in the UK.

The DNO incentives from the UK are applied, with losses valued at £48/MWh and the DNO receiving £2.50/year for every kW of DG connected. For illustration, the adopted target level of losses is equal to the initial losses, i.e., with no DG connected (Table 1).

The network deferment benefit considers the simple case that the substation transformers are close to their thermal rating and would need replacing in the near future. A single value for network deferment benefit was chosen to be £250/kW of DG connected which is within the range suggested by the literature for deferral of transformer upgrades for 5 years, e.g. [35].

The multi-year multi-period OPF was run to capture the viewpoints of both DG-owning and unbundled DNOs using their respective objective functions, (1) and (3). In order to investigate the impact of different

DG operating patterns throughout the planning horizon, several cases were analyzed considering the number of hours of generation according to Fig. 1:

A. Operation for whole time;

B. Operation at maximum, normal, and medium load;

C. Operation at maximum and normal load; and,

D. Operation at maximum load only.

Simulation results for the DG-owning DNO are shown in Table 2, for natural gas and diesel. Table 3 presents the results corresponding to the unbundled DNO, where the objective function (3) is independent of the fuel used by the generation units.

For a DG-owning DNO the type of the generator, i.e., installation and O&M costs, plays a crucial role. It can be verified in Table 2 that diesel gensets, typically used for peak loads, are indeed only economically viable when used for such periods (case *D*). On the other hand, for such short operating periods, gas engines cannot be placed due to their high installation costs. However, for longer operational periods (cases *A* to *C*) the lower cost per kWh of these DG units proves to be economically sound.

Cases *A*, *B* and *C*, for diesel gensets show identical allocation of new generation capacity. As mentioned previously, from year 10 the 6 MVA transformer would need to be upgraded (Fig. 3); in these cases, the OPF minimises the “negative” overall costs by installing only the DG capacity required to keep voltages and power flows within limits. This minimum DG capacity that fulfils the technical constraints is also met when evaluating case *D* with natural gas engines.

It can be concluded from the results in Table 2, that the loss incentive (*LI*) plays a minor role when compared to the benefit from network deferral (*ND*), energy sales (*R*), net of the costs of O&M and installation (*OM*, *CDG*). In fact, cases *A*, *B* and *C* for natural gas are mostly driven by the energy sales; whereas case *D* for diesel is profitable due to the network deferral benefit.

Here, the assumption was that a power purchase agreement specifies a single electricity sales price rate irrespective of the time-of-day. With electricity prices typically much higher at peak times the effect of a doubling in sales price (£94/MWh) applying to the peak period alone was examined. Despite a doubling in revenue in case *D*, and proportionately smaller increases as the operational period increases (i.e. *C*: 2.5%

to *A*: 0.8%), the impact on the capacity preferences was found to be zero (i.e. capacity as in Table 2) as the network limits constrain the ability to exploit this increased revenue by raising capacity.

For the unbundled DNO regulatory scenario, where only capacity (*CI*) and loss incentives (*LI*) are considered, the convenient – from the DNO point of view – limit for new generation capacity will also depend on the loading levels. Here, the loss incentive tends to promote a modest penetration of capacity to avoid losses associated with the reverse power flows experienced with the larger DG units favoured by the DG-owning DNO. Thus, when DG is projected to run continuously, i.e., case *A*, the reduction of losses plays a major role. However, the share of *LI* is reduced as higher loadings levels are taken into account, when the capacity incentive becomes more important. Indeed, in cases *C* and *D*, *CI* overtakes the income from the loss incentive. Moreover, for the latter case, the gains from generation capacity turn to be such a driver that *LI* becomes negative, i.e., the DNO is penalised (losses above target levels).

If the loss incentive was not present, the capacity incentive alone would make the optimal connection be the maximum technically possible (see Appendix, Table A.1). As such, it is the inclusion of the loss incentive that alters the benefit of DG as perceived by the unbundled DNO. On the other hand, by only taking into account the loss incentive, as it might be the case for certain DNOs, even smaller capacities of DG would be allocated (see Appendix, Table A.2).

By comparing the economically viable results presented in Table 2 to those from Table 3, one it appears that the prohibition of DG ownership of DG within the unbundling regulatory framework severely constrains new DG capacity due to the lack of incentives. In fact, generation levels found for the DG-owning DNO are close to the maximum capacity that the network is technically able to accept (see Appendix, Table A.1). While for peak load, i.e., case *D*, both sets of rules see DNOs benefit from larger amounts of DG capacity; they largely differ when other loading levels are taken into account. The reasoning behind the larger DG capacity for operation at peak time only is due to the larger export possible before voltage or thermal constraints are reached. For cases where DG operates at all times, the lower load conditions create progressively more significant reverse power flows and voltage rise and, consequently constrains the maximum connectable capacity.

To illustrate the impact of DG connection on network loading, Figure 4 shows key network characteristics for each year for a diesel DG-owning DNO with the operating scenario *D* which had the highest DG penetration. While the minimum and maximum bus voltages, as well as the usage of lines and transformers, are within the statutory limits during the planning horizon, the OPF technique pushes the network ability to cope with DG capacity to the boundaries (year 1). In this case, the demand growth over the years eases the voltage profile and the power flows, as opposed to what happens in the original network without DG (Figure 3).

6. Discussion

This paper makes an initial attempt to quantify the impact of DG ownership rules on DNO preferences for DG. It shows that the ability to place DG allows the DNO to capture the benefits of network deferral and connect more capacity. Although it borrows heavily from UK mechanisms, the approach and outcomes should be broadly applicable elsewhere.

In order to capture the potential benefits from network deferral, reduced distribution network costs and improved overall energy efficiency at European level, it may be necessary to promote the European Directive requirement for DNOs to consider the use of DG as a means of supplementing network capacity. The key issue in the debate over DNO ownership of DG surrounds the need for the DNO to facilitate competition in generation by providing and, importantly, being seen to provide, transparent non-discriminatory access to all.

The approach favoured in the UK and highlighted by several EU wide studies [28] is to use cost-reflective charging to promote appropriate behaviour from developers by rewarding them with a share of the benefits brought by appropriate connection and operation. However, cost-reflective charging schemes tend to be fairly shallow which means that the signalling is weakened [15]. With aspects other than network charges potentially dominating the decision to site DG, there remains a risk that, despite best intentions, cost-reflective charging may not result in DG developers connecting in the most appropriate locations. As a result, the opportunities offered by DG may be lost as the DNO has no option but to upgrade the network in the traditional manner.

A more direct route (perhaps undertaken in combination with cost-reflective charging) would be to of-

fer more explicit signals by inviting competitive bids for capacity and other service from developers. Again there is a risk that competitive bids would not be forthcoming, as developers' higher rates of return, may result in bids that exceed the network-only option (although a DNO-provided DG may be cheaper).

Should the approaches above not deliver the benefits expected, DG ownership by DNOs could be allowed under very strict conditions, e.g., DG ownership could only be permitted as a last resort after other avenues (e.g. charging or tendering) have been exhausted; and that operation could be restricted to specific periods, e.g. peak load, in order to remove the significant incentive from energy sales. They key challenge in this case would be ensuring that the processes and decision-making by the DNO are transparent and fully auditable.

The simple approach to representing network deferral benefit used here was effective in examining the DNO's behaviour. However, a uniform benefit throughout the network is unlikely to be applicable in all cases. One extension would be to attribute different deferral benefits to each DG unit where they are evidently contributing to separate deferral cases. However, a more sophisticated approach that automatically detects and accounts for each deferral opportunity is required. With further work an approach similar to [4] or [36] could be implemented within the multi-year multi-period OPF framework.

In the case study presented here, for reasons of simplicity the DGs are connected at the start of the planning period although a technical necessity appears much later. This contributes significantly to the incentive to connect DG provided by energy sales in the case of the high capital cost low operational cost gas generator (although the opposite is true for high operational cost diesel gensets). What is also apparent is that as the date for network upgrade moves closer, the present value of the deferment benefit increases significantly adding greatly to the incentive to deploy DG.

One of the assumptions made here and indeed in most other studies relating to network deferral is that a DG investment can be a direct substitute for 'wires and poles' assets by applying the same discount rate to both. A strict reading of financing states is that discount rates should reflect the risk of each cash flow separately. It is apparent that a DG unit cannot have the same risk profile as traditional network assets and additional research would help clarify this.

7. Conclusions

DG can contribute to the development and management of more active and, potentially, more efficient distribution networks within Europe. Nevertheless, the prohibition of DNO ownership of DGs implied by unbundling rules creates an additional hurdle to the use of DG in lieu of network assets. This paper examines the different regulations for DNO ownership of DG and how they influence the optimal connection of new generation within existing networks. Overall, the paper highlights the need for schemes and practices that better incentivise DG deployment to the benefit of the network.

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9. Appendix

9.1. Multi-year multi-period OPF formulation

The following sets, parameters and variables apply to the model:

Sets:

B	Set of buses (indexed by b)	X	Set of external sources (indexed by x)
L	Set of lines (indexed by l)	DL	Set of demand levels (indexed by dl)
G	Set of new distributed generators (indexed by g)	Y	Set of the years analysed (indexed by y)

Parameters:

$d_b^{(P,Q)}$	(P,Q), real and reactive power peak load at bus b (year 0)	$q_x^{(+,-)}$	(max/min) reactive power output of x
$V_b^{(+,-)}$	(max/min) voltage at b	p_g^+	max real power output of g
$tap_l^{(+,-)}$	(max/min) tap ratio for the device located in l	$\beta_l^{(1,2)}$	(start,end) bus of line l
b_0	Reference/slack bus	f_l^+	Maximum power flow on l
β_g	Location of generator g	η_{dl}	Demand level relative to peak
β_x	Location of external source x	τ_{dl}	Duration of dl
ϕ_g	power angle of g	a_y	Number of the year y
$p_x^{(+,-)}$	(max/min) real power output of x	deg	Annual demand growth

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Variables:

$V_{b,dl,y}$	Voltage at b, for each combination of demand levels at year y	$q_{x,dl,y}$	Reactive power output of x
$\delta_{b,dl,y}$	Voltage angle at b	$f_{l,dl,y}^{(1,2),P}$	Real power injection onto l at (start,end) bus
p_g	Real power output of g (nominal capacity)	$f_{l,dl,y}^{(1,2),Q}$	Reactive power injection onto l at (start,end) bus
$p_{x,dl,y}$	Real power output of x		

Then the objectives functions OF_1 and OF_2 will be maximised subject to, $\forall dl \in DL$ and $\forall y \in Y$:

1) *Capacity/supply constraints for the interconnection to external network (slack bus),* $\forall x \in X$.

$$p_x^- \le p_{x,dl,y} \le p_x^+ \quad \wedge \quad q_x^- \le q_{x,dl,y} \le q_x^+ \tag{8}$$

2) *Capacity/supply constraints for the distributed generators,* $\forall g \in G$.

$$0 \le p_g \le p_g^+ \tag{9}$$

3) *Voltage level constraints,* $\forall b \in B$.

$$V_b^- \le V_{b,dl,y} \le V_b^+ \tag{10}$$

4) *Reference bus where voltage angle at the reference bus is zero.*

$$\delta_{b_0,dl,y} = 0 \tag{11}$$

5) *Kirchhoff current law.*

Real power conservation, $\forall b \in B$.

$$\sum_{g \in G | \beta_g = b} p_g + \sum_{x \in X | \beta_x = b} p_{x,dl,y} = \sum_{l \in L | \to b} f_{l,dl,y}^{T,P} + d_{b,dl}^P \cdot \eta_{dl} \cdot (1 + deg)^{a_y} \tag{12}$$

Reactive power conservation, $\forall b \in B$.

$$\sum_{g \in G | \beta_g = b} p_g \cdot \tan(\phi_g) + \sum_{x \in X | \beta_x = b} q_{x,dl,y} = \sum_{l \in L | \to b} f_{l,dl,y}^{T,Q} + d_b^Q \cdot \eta_{dl} \cdot (1 + deg)^{a_y} \tag{13}$$

The total power injection onto lines at b is represented by $f^{T,(P,Q)}$, including the corresponding capacitance term for the reactive power line injections.

6) *Kirchhoff voltage law,* $\forall l \in L$.

$$f_{l,dl,y}^{(1,2),P} = f_{l,dl,y,(1,2)}^{KVLP}(V,\delta) \quad \wedge \quad f_{l,dl,y}^{(1,2),Q} = f_{l,dl,y,(1,2)}^{KVLQ}(V,\delta) \tag{14}$$

Terms $f_{l,dl,y,(1,2)}^{KVLP}(V,\delta)$ and $f_{l,dl,y,(1,2)}^{KVLQ}(V,\delta)$ are the standard Kirchhoff voltage law expressions for the power injections onto lines at the two terminal buses (denoted 1 and 2).

7) *Flow constraints at each end of lines,* $\forall l \in L$.

$$\sqrt{\left(f_{l,dl,y}^{1,P}\right)^2 + \left(f_{l,dl,y}^{1,Q}\right)^2} \le f_l^+ \quad \wedge \quad \sqrt{\left(f_{l,dl,y}^{2,P}\right)^2 + \left(f_{l,dl,y}^{2,Q}\right)^2} \le f_l^+ \tag{18}$$

9.2. Supplementary results

Table A.1 shows the maximum generation capacity that can be installed in the 69-bus network, considering the loading levels, load growth and technical constraints presented in Section 5. The overall optimal DG capacity increases as the operating hours are restricted. This occurs due to the less stringent constraints particularly as the removal of lower demand periods allows more capacity to be connected.

Table A.2 presents the DG capacity that maximises the loss incentive benefit for each operating scenarios over the 15-year horizon.

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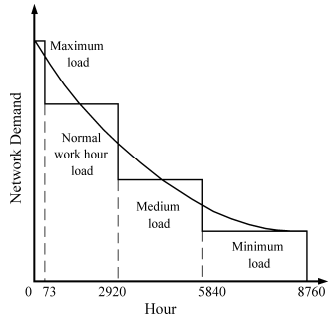

Fig. 1. Load duration curve.

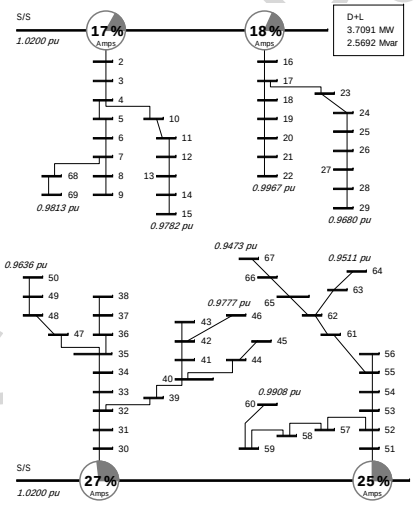

Fig. 2. 69-bus network one-line diagram. Power flow results considering base year and peak load (Table 1).D+L: Total demand and line losses.

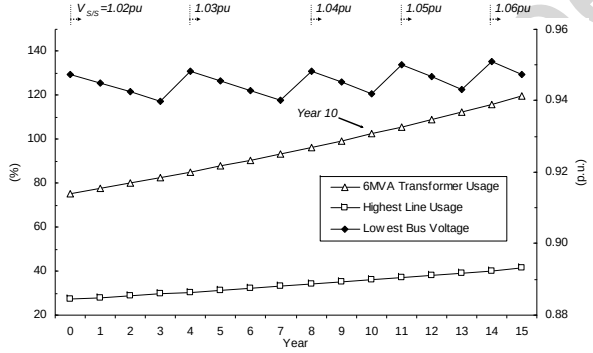

Fig. 3. Yearly analysis of the 69-bus network during peak load (no new generation capacity). Taps at the substation ($V_{S/S}$) are set to maintain voltage profiles within statutory limits.

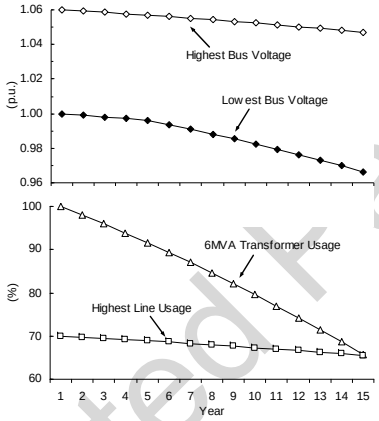

Fig. 4. Yearly analysis of the 69-bus network considering DG Operating Scenario D – Diesel Generator.

Table 1

Load Band	Duration (H)	Active Power (MW)	Reactive Power (MVAr)	Losses (MW)
Minimum	2920	1.4294	0.9789	0.0204
Medium	2920	2.1442	1.4683	0.0468
Normal	2847	2.8589	1.9578	0.0849
Maximum	73	3.5736	2.4472	0.1355

Table 2

DG-owning DNO: Optimal Capacity and Present Value Costs/Revenues Over Planning Horizon

	DG Location	Gas				Diesel			
		DG Operating Scenario							
		A	*B*	*C*	*D*	*A*	*B*	*C*	*D*
Capacity (MW)	5	1.3297	1.4645	1.5996	---	----	----	---	2.1320
	13	0.2410	0.2633	0.2872	0.0746	0.0746	0.0746	0.0746	---
	27	0.9416	1.0389	1.1444	0.2643	0.2643	0.2643	0.2643	1.3507
	35	0.9881	1.0756	1.1617	0.5124	0.5124	0.5124	0.5124	0.3071
	40	1.2350	1.3675	1.5089	---	---	---	---	2.3322
	57	2.1170	2.3522	2.5893	---	---	---	---	3.6221
	65	0.4338	0.5218	0.5892	0.5067	0.5067	0.5067	0.5067	---
	Total DG	**7.2862**	**8.0839**	**8.8802**	**1.3580**	**1.3580**	**1.3580**	**1.3580**	**9.7441**
	Objective Function Breakdown								
(£ 000s)	*ND x Pg*	1821.5	2021.0	2220.0	339.5	339.5	339.5	339.5	2436.0
	LI	-468.7	-341.2	-183.4	1.2	74.4	66.2	39.6	-5.6
	R	24181.0	17885.6	9823.7	37.6	4506.9	3004.6	1502.3	269.5
	OM	14405.7	10655.3	5852.4	22.4	14383.7	9589.1	4794.6	860.1
	CDG x Pg	4371.7	4850.3	5328.1	814.8	135.8	135.8	135.8	974.4
	Objective Function	**6756.4**	**4059.8**	**679.8**	**-459.0**	**-9598.7**	**-6314.6**	**-3048.9**	**865.4**

Table 3

Unbundled DNO: Optimal Capacity and Present Value Costs/Revenues over Planning Horizon

	DG Location	DG Operating Scenario			
		A	*B*	*C*	*D*
Capacity (MW)	5	0.4024	0.4949	0.6683	1.7865
	13	0.1600	0.1878	0.2220	0.3482
	27	0.4459	0.5323	0.6623	1.3241
	35	0.4640	0.5529	0.6845	1.3626
	40	0.4512	0.5478	0.7144	1.5764
	57	0.5158	0.6482	0.9245	2.5182
	65	0.3928	0.4532	0.5248	0.7625
	Total DG	**2.8321**	**3.4170**	**4.4008**	**9.6785**
	Objective Function Breakdown				
(£ 000s)	*CI x Pg*	57.1	68.9	88.7	195.0
	LI	122.4	113.7	68.6	-3.4
	Objective Function	**179.5**	**182.6**	**157.3**	**191.6**

Table A.1

Maximum New Generation Capacity for the Studied Planning Horizon

	DG Location	DG Operating Scenario			
		A	*B*	*C*	*D*
Capacity (MW)	5	0.2391	0.5419	1.9914	2.1320
	13	0.7317	0.6895	---	---
	27	0.9957	1.1139	1.2322	1.3507
	35	0.9061	1.0307	0.0022	0.3071
	40	1.4529	1.5643	2.3268	2.3322
	57	2.6772	3.1794	3.3996	3.6221
	65	0.3166	---	---	---
	Total DG	**7.3191**	**8.1197**	**8.9521**	**9.7441**

Table A.2

Optimal Capacity considering the Loss Incentive (*LI*) alone over Planning Horizon

	DG Location	DG Operating Scenario			
		A	*B*	*C*	*D*
Capacity (MW)	5	0.3267	0.3807	0.4361	0.5429
	13	0.1547	0.1798	0.2056	0.2556
	27	0.4062	0.4724	0.5406	0.6728
	35	0.4254	0.4947	0.5662	0.7054
	40	0.3860	0.4494	0.5146	0.6404
	57	0.3805	0.4433	0.5082	0.6325
	65	0.4215	0.4454	0.5089	0.6334
	Total DG	**2.5010**	**2.8657**	**3.2802**	**4.0829**
Objective Function (£ 000s)		**125.7**	**119.3**	**80.1**	**3.2**