DG Impact on Investment Deferral: Network Planning and Security of Supply

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David T-C. Wang, Luis F. Ochoa, *Member, IEEE*, and Gareth P. Harrison, *Member, IEEE*

***Abstract*—Despite the technical challenges in properly accommodating distributed generation (DG), one of the major and well-recognised benefits is the ability of DG to defer future demand-related network investment. It is, however, often poorly represented in existing planning approaches and analysis ignores the potential security of supply benefits. Here, a novel, more integrated, approach is presented wherein reinforcements required by system security standards (e.g., N-1) are also taken into account. The DG contributions to system security provided by UK Engineering Recommendation P2/6 are adopted, enabling the methodology to quantify the deferment produced by DG considering both demand growth- and system security-related investment. The methodology employs the successive elimination algorithm together with multistage planning and is applied to a generic, meshed, UK distribution network. Results show that, despite differences between technology types, significant economic benefits can be harnessed when strategically incorporating DG at the planning stage.**

***Index Terms*—Distribution networks, distributed generation, investment deferral, planning**

I. Introduction

DIVERSIFICATION of the energy mix is one of the main challenges in the energy agenda of governments worldwide. Technology advances together with environmental concerns have paved the way for the increasing integration of Distributed Generation (DG) seen over recent years. Combined heat and power (CHP) and renewable technologies are being encouraged and their penetration in distribution networks is increasing. This scenario presents Distribution Network Operators (DNOs) with several technical challenges in order to properly accommodate DG developments [1, 2]. However, depending on factors such as location, size, technology and network robustness, DG might also be beneficial to DNOs [3-6]. While reductions in power losses are a direct technical benefit for the DNO, its economic impact will depend on the regulatory framework. A more tangible, but less well understood, economic benefit for DNOs is the decongestion of network assets due to demand growth [7-12], as DG has the ability to help avoid or defer reinforcements.

The benefits (and negative impacts) brought about by DG need to be quantified in order to create a level playing field for both DNOs and DG developers. However, from the distribution planning perspective, where demand-led reinforcements traditionally represent costly capital expenditure, the effect that DG might have on deferring such investment is largely neglected. European Directive 2003/54/EC [13] Article 14/7 states: "When planning the development of the distribution network, energy efficiency/demand-side management measures and/or distributed generation that might supplant the need to upgrade or replace electricity capacity shall be considered by the distribution system operator". Nonetheless, there is no specification on how to implement it.

The assessment of the investment deferral has been addressed in some studies. Brown *et al*. [14] proposed a successive elimination (SE) algorithm for distribution network expansion considering the specific siting of generation units. It presents a simple planning technique and can be used to calculate the investment required by the non-DG and DG scenarios, thus obtaining the corresponding monetary benefit.

Mendez *et al*. [8] demonstrated the impact of different DG penetration and concentration levels and technology mixes on allowable load growth without the need for reinforcements. While the results clearly show the impact DG has on postponing investment, this particular study cannot be used for quantifying the relative benefit that a generation unit may bring about according to its location.

Gil and Joos [9] developed an approach based on the amount that network radial feeder currents are reduced by a DG unit. Their definition of reinforcement deferment was based on the time required for feeder currents to reach the pre-DG level. This calculation of the deferment, however, is not appropriate since the economic benefits of DG can only be quantified accurately when deferment is measured relative to the time when the reinforcement costs would be incurred [10].

The methodology proposed in this paper builds substantially on initial work [10] which combined the successive elimination approach from [14] with multistage planning in order to assess the deferment of demand-led investment. With reinforcement also driven by security of supply standards, such as the UK's Engineering Recommendation (ER) P2/6 [15], the work presented here caters for those requirements. This is particularly relevant as ER P2/6 specifies a mechanism by which DG contributes to system security by acknowledging a fraction of the nominal capacity of the generator during a circuit outage (N-1 condition). Incorporating this contribution enables the

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methodology to quantify the impacts of DG on both demand growth- and system security-related investment.

In this work, a generic, meshed, UK distribution network [16] is evaluated considering the connection of both intermittent (e.g., wind power) and firm (e.g., CHP) DG units. The investment deferral is defined as that when reinforcements that are required to prevent system constraint violations, such as voltage and thermal limits (during normal and N-1 operation), are postponed as a result of DG connection. Single DG connections are examined in order to investigate the corresponding effects on investment deferral.

This paper is structured as follows: the contribution of DG to system security adopted by UK ER P2/6 is briefly explained in Section II. Section III presents the methodology for assessing investment deferral while the generic distribution network is analysed in Section IV. Finally, discussion and conclusions are presented in Section V and Section VI, respectively.

II. Contribution of DG to System Security

DG connected to the distribution network might, to some extent, be able to contribute to system security, by maintaining supply to a defined level of demand under specified outage conditions. In the UK, Engineering Recommendation P2/6 [15] specifies (indicative) contribution factors, known as 'F-factors', to determine the contribution from a given DG plant based on its declared net capacity (declared capability of the DG plant in MW less normal site power consumption). Tables I and II present the F-factors for different types of firm (non-intermittent) and intermittent generation, respectively. For the former, F-factors depend on the technology and the number of generating units, while the latter depends on the period of continuous generation (i.e., persistence). The duration of the persistence is selected for the appropriate condition (e.g., switching, maintenance).

To illustrate the impact of the F-factors on planning investment, consider Fig. 1 which presents an example system with DG plant. Two cases are analysed: (1) two identical 10MW CHP generation units or (2) a 20MW wind farm.

TABLE I
F-factors in % for Non-Intermittent DG [15]

Type of generation	Number of units 1	2	3	4	5	6	7	8	9	10+
Landfill gas	63	69	73	75	77	78	79	79	80	80
CCGT	63	69	73	75	77	78	79	79	80	80
CHP sewage treatment using a spark ignition engine	40	48	51	52	53	54	55	55	56	56
CHP sewage treatment using a Gas Turbine	53	61	65	67	69	70	71	71	72	73
Other CHP	53	61	65	67	69	70	71	71	72	73
Waste to energy	58	64	69	71	73	74	75	75	76	77

TABLE II
F-factors in % for Intermittent DG [15]

Type of generstion	Persistence, T_m (hours) 1/2	2	3	18	24	120	360	>360
Wind farm	28	25	24	14	11	0	0	0
Small hydro	37	36	36	34	34	25	13	0

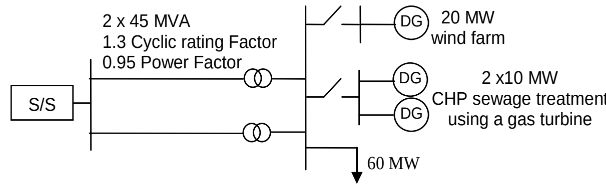

Fig. 1 Example system with DG.

The DG plant is connected to a bus with a 60MW load. The substation (S/S) supplies via two 45MVA, 0.95 power factor transformers with a 1.3 cyclic rating factor.

ER P2/6 states that for load of 60MW, only the first circuit outage (FCO), i.e., one of the transformers, needs to be considered [15]. Without DG, the maximum amount of load that can be supplied following the outage of the most crucial circuit, i.e. the Network Capability, would be:

$$1\times 45\times 1.3\times 0.95 = 55.6\text{MW}$$

Clearly, the demand cannot be met and the circuit would need reinforcement, typically by adding a third transformer in parallel. If, however, DG is to be taken into account, the F-factor for the CHP plant with two generation units would be 61% (Table I). For the wind farm, the required 3 hour persistence for switching implies an F-factor of 24% (Table II). The contribution of each DG plant is calculated as follows:

$$\text{Contribution}_{\text{CHP}} = 2\times 10\times 0.61 = 12.2\text{MW}$$

$$\text{Contribution}_{\text{WIND FARM}} = 0.24\times 20 = 4.8\text{MW}$$

The final network capability after a first circuit outage considering the CHP plant is 67.8MW, while the contribution from the wind farm allows up to 60.4MW. In both cases the security of supply requirement is fulfilled without further network investment.

III. Methodology

Distributed generation is able to offset local demand, and therefore postpone load growth-led investment. Nevertheless, system security-driven reinforcements (e.g., redundancy of circuits) cannot rely entirely on DG plants due to availability issues. In this context, the contribution to system security provided by ER P2/6 can be considered in a more integrated approach to assess demand growth and system security requirements that drive network investment. While decisions on placing and sizing of DG units are not generally made by DNOs (availability of resources normally determines connection site), nonetheless, studies that supply information regarding the most beneficial connection points and generation capacities – from the network point of view – might be used within a framework of incentives or charging schemes.

In order to evaluate the effect that the placement of generation units may have on the network expansion costs over the planning horizon, the reinforcements required by the original demand-only (no DG) and DG scenarios need to be determined. In the UK, automated planned approaches have not achieved widespread use by DNOs due to concerns over representation of complex aspects or limited auditability. They are, however, used elsewhere and feature regularly in academic literature. The discrete nature of network upgrades limits applicability of classical optimisation methods but a wide range of metaheuristic techniques (e.g., Genetic Algorithms, Simulated Annealing, Tabu Search) and integer programming approaches have been documented [17]. The successive elimination method applied here is a so-called greedy heuristic. It is straightforward and rule-based, making the process easily understandable by the planner and other market participants due to the use of a cost-effectiveness index. While other heuristic optimization planning strategies for distribution networks commonly found in the literature may give better solutions it will still produce a satisfactory solution.

Here, a two-phase approach has been developed to consider a given case of load growth, planning horizon, and presence or absence of new DG. Firstly, the successive elimination method is used to evaluate the capacity upgrades needed by the distribution network. Secondly, the multistage planning analysis provides the necessary schedule for the investment. Finally, the total expansion planning costs are calculated for the studied case. The difference between the costs required for the original scenario and the DG scenarios will correspond to the value of investment deferral produced by the connection of new generation. The following subsections describe in detail each phase of the method.

A. Successive Elimination Method

The fundamental concept of the successive elimination (SE) method presented in [10] is to initially overbuild the network considering the loading at the end of the planning horizon. All expansion options, such as new lines and transformers, are taken into account. Then, the least cost-effective option, in terms of capacity margin, is removed until the further removal of any remaining candidate would cause the violation of system constraints such as voltage and thermal limits. For distribution network planning to cater for security of supply standards, N-1 security constraints (i.e., first circuit outage) and the corresponding contribution from connected DG units are incorporated to the SE method. Thus, the cost-effectiveness evaluation of each expansion option will ensure the adequate operation of the network with and without outages.

Here, planning expansion options are not restricted to the addition of similar assets such as the connection in parallel of a transformer with a capacity equal to that already in place). Therefore, initially from the overbuilt network, the cost-effectiveness evaluation of a given section of the network (overhead lines, cables or transformers) will consider either the upgrade of the assets or the addition of a parallel reinforcement (as illustrated in Fig. 2). If one of these two options is the least cost-effective of all options in the network, then the remaining one is adopted. The next cost-effectiveness evaluation is performed from that new configuration.

Considering the load as that forecast at the end of the planning horizon, the network is initially overbuilt by connecting to each section the maximum number possible of those reinforcements with the largest capacity available. Then, the following steps are applied.

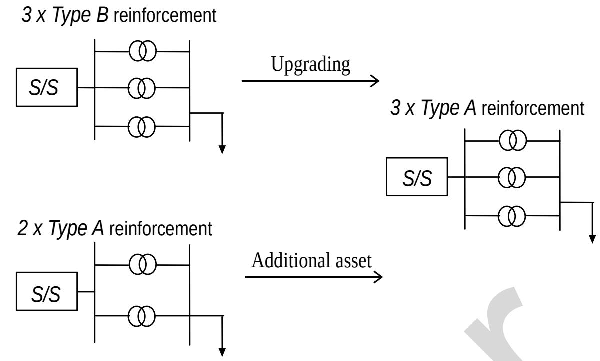

Fig. 2 Expansion planning options to 'overbuild' a given section of the network: upgrading of assets and addition of a parallel reinforcement.

<u>*Step 1*</u>. Calculation of the cost-effectiveness (CE) of each expansion option identified in the network. If for a given expansion option constraint violations occur (voltage and thermal constraints are verified for both normal operation and N-1 security requirements considering the forecast demand), the cost-effectiveness of this option is set to a very large number, otherwise:

$$CE_a = \frac{\sum_{k \neq a} \left| P_{k\ \text{new}} - P_{k\ \text{original}} \right|}{Cost_a} \tag{1}$$

where CE_a is the cost-effectiveness measurement of option a in MW/\$, $P_{k\ \text{original}}$ is the MW flow on branch k before eliminating expansion option a, $P_{k\ \text{new}}$ is the MW flow on branch k after eliminating expansion option a, and $Cost_a$ is the cost of expansion option a.

<u>*Step 2*</u>. If all CEs are set to a very large number, then the final expansion plan has been determined. Otherwise, eliminate the expansion option with the lowest CE and go to Step 1.

B. Multistage Planning Analysis

The purpose of the multistage planning analysis is to schedule the implementation of the reinforcements obtained from the SE method along the planning horizon. Thus, by scheduling the reinforcements according to the demand growth it is possible to evaluate the investment deferral caused by the connection of DG.

Starting at the year at the end of the planning horizon and, with the expansion options identified found by the SE method, the multistage analysis requires the following steps:

<u>*Step 1*</u>. Assume the connection of DG unit(s) along the whole planning horizon and calculate the corresponding capacity contribution using the F-factors.

<u>*Step 2*</u>. Use the cost-effectiveness technique to identify those candidates that are not necessary this year, eliminating the least cost-effective expansion option. Repeat this until all the remaining options are essential to prevent any system violations for both normal operation and N-1 security requirements.

<u>*Step 3*</u>. Consider the demand forecast for the previous year (i.e., year = year–1). Stop if it is the base year, otherwise go to Step 2.

In applying the multistage planning analysis for the no-DG scenario, Step 1 is ignored.

C. *Investment Deferral*

From the previous two subsections, both the reinforcements for the network expansion and the corresponding scheduling of investment can be determined. To obtain the total investment incurred by each planning scenario studied, the present value of each upgraded asset should be calculated. The total present value (PV) cost of a given expansion plan is calculated by:

$$PV = \sum_{t=1}^{h}\sum_{i=1}^{n}\frac{C_{i,t}}{(1+\rho)^t} \tag{2}$$

where h is the number of years in the planning horizon, n is the number of reinforcements required for year t, C_i is the cost of asset i required for year t, and ρ is the discount rate.

The investment deferral, as a benefit brought about by the connection of new DG capacity, is then calculated by subtracting the PV of the total investment required by a given DG planning scenario from that of the original (no new generation) planning scenario:

$$Inv.\,Deferral = \left.\sum_{t=1}^{h}\sum_{i=1}^{n}\frac{C_{i,t}}{(1+\rho)^t}\right|_{no\ DG} - \left.\sum_{t=1}^{h}\sum_{i=1}^{n}\frac{C_{i,t}}{(1+\rho)^t}\right|_{DG} \tag{3}$$

IV. Application

In this section the investment deferral produced by the connection of DG units is investigated on a generic distribution network. Different DG locations and two different technologies (CHP and wind power), with their corresponding security contributions, are considered. Finally, the deferred investment is also evaluated by the contribution factor applied to DG units.

A. *Network Characteristics*

The proposed methodology is applied to the 81-bus meshed suburban distribution network depicted in

Fig. 3. The full specification of EHV Network 4 can be obtained in [16]. Power is supplied to the meshed network from a single grid supply point and two interconnectors linking neighbouring networks at 132kV. There are 32 loads scattered throughout the network of different voltage levels (33, 11 and 6.6kV). Total peak load in the base year is 151MW, an annual load growth of 2% and a 10 year planning horizon is assumed. Any reinforcement postponed beyond the horizon is assumed to be enacted at year 10 instead of complete avoidance of the reinforcement. This is relatively conservative as it will understate the true deferment. A cyclic rating of 1.1 is assumed for transformers. The discount rate is 6%.

System security standard ER P2/6 [15] specifies that a group demand of less than 12MW is not required to be restored immediately. The only load bus exceeding such a limit is bus 1112. However, given the meshed characteristics of EHV Network 4, the adopted N-1 security constraint affects those lines and transformers that transfer capacity to more than one demand group. The lines between the interconnectors and the main network are excluded from the N-1 analysis.

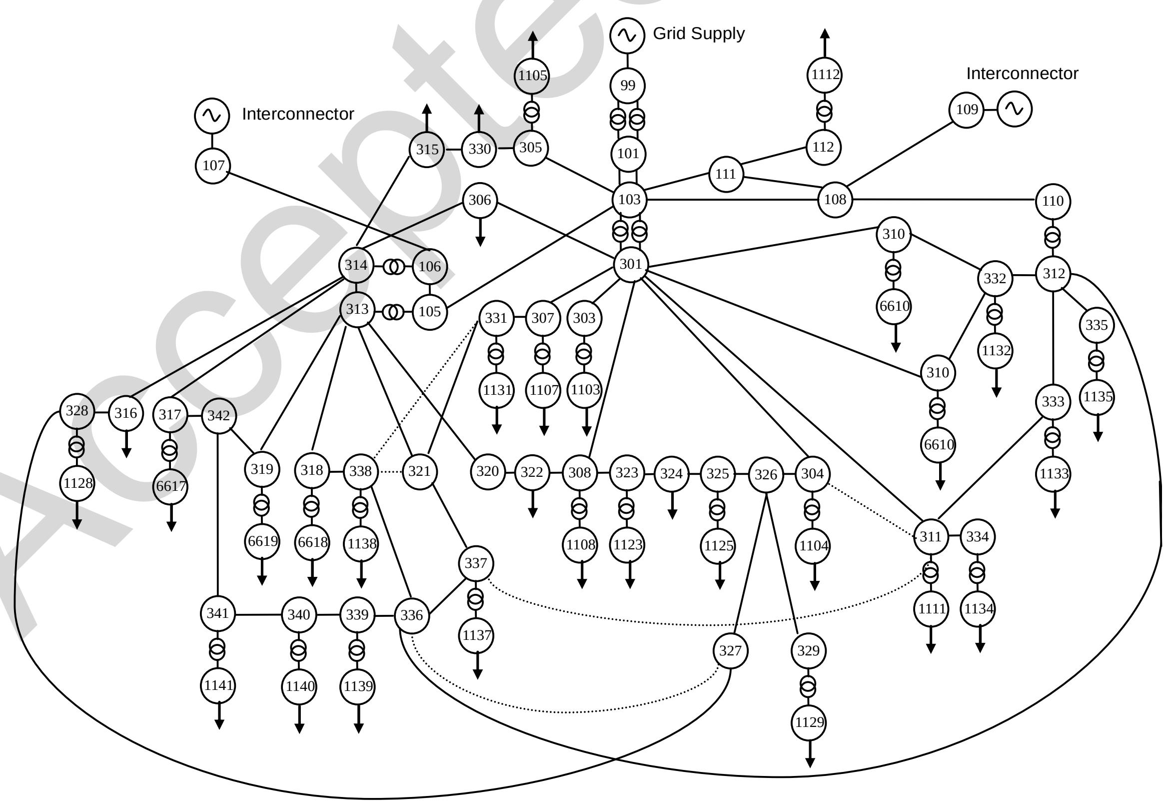

Fig. 3 UK GDS EHV Network 4 - Meshed suburban network.

B. Expansion Plan without DG

The reinforcements required for the case without DG, along with the commissioning schedules and costs (based on [18]), are shown in Table III. The term 'upgrade' refers to the replacement of existing lines, whereas 'addition' indicates that the reinforcements are connected in parallel with the existing ones. The total planning cost in present value is US$2.9m. Most of the reinforcements will be required within the first two years. With the load at bus 1112 greater than 12MW an extra transformer (T112-1112) is needed to meet the security requirements. In fact, if the security constraints were not applied, the only reinforcement required would be that of line L101-103. The majority of the upgrades specified are for parallel lines. In the UK, where additional wayleave requires planning permission this could be a challenge; therefore where DG is able to defer such upgrades it would be regarded as especially beneficial.

TABLE III
SCHEDULE OF REINFORCEMENTS REQUIRED (NO-DG CASE)

Name	Type	Capacity (MVA)	Cost(US$k/km)	Length (km)	Year	P.V. cost (US$k)
L101-103	upgrade	2 x 120	400	4.2	7	1117.30
L103-105	parallel	1 x 120	200	3.5	8	439.19
L301-304	parallel	1 x 30	120	1.1	1	124.53
L304-326	parallel	1 x 30	120	0.9	2	96.12
L311-337	parallel	1 x 30	120	0.5	0	60.00
L313-318	parallel	1 x 30	120	0.5	2	53.40
L313-319	parallel	1 x 30	120	1.6	0	192.00
L319-342	parallel	1 x 30	120	0.2	8	15.06
L341-342	parallel	1 x 30	120	1.7	0	204.00
L111-112	parallel	1 x 120	200	0.6	0	120.00
T112-1112	parallel	1 x 30	500	-	0	500.00
					Total	2921.59

C. Locational Impact of DG

The ability of DG to defer investment depends on its location relative to the load and highly utilised assets. To illustrate this the impact of a single 10MW DG connected, in turn, to each load nodes in the network is considered. Two alternative generation types are considered: a five-unit CHP plant with an F-factor of 69% or a wind farm. Assuming the wind resource is equally available across the network and the persistence T_m required for the wind farm is 3 hours, the F-factor is 24%. For the security analyses, the CHP plant and the wind farm would contribute 6.9MW and 2.4MW of capacity, respectively. Fig. 4 presents the corresponding results, differentiating the reinforcements required at 33 and 132kV.

As expected, a given DG plant of the same size and technology connected to different locations resulted in significant variations of the potential investment deferral. When assuming a CHP plant (Fig. 4a), the values vary between US$5.9k (buses 1132 and 6610) to US$396.7k (bus 1112). For the wind farm (Fig. 4b) no benefit was obtained in some cases, with the maximum deferment (US$49.1k) found when accommodated at bus 1128. Clearly, more investment is postponed when the higher capacity contribution (i.e., CHP) is taken into account. In addition to the 33kV reinforcements affected by the reductions in power flows provided by the CHP plant (as seen for bus 1112), the cumulative impact defers 132kV asset reinforcements. The connection of the wind farm to buses 324, 1125 and 1129, however, offers no

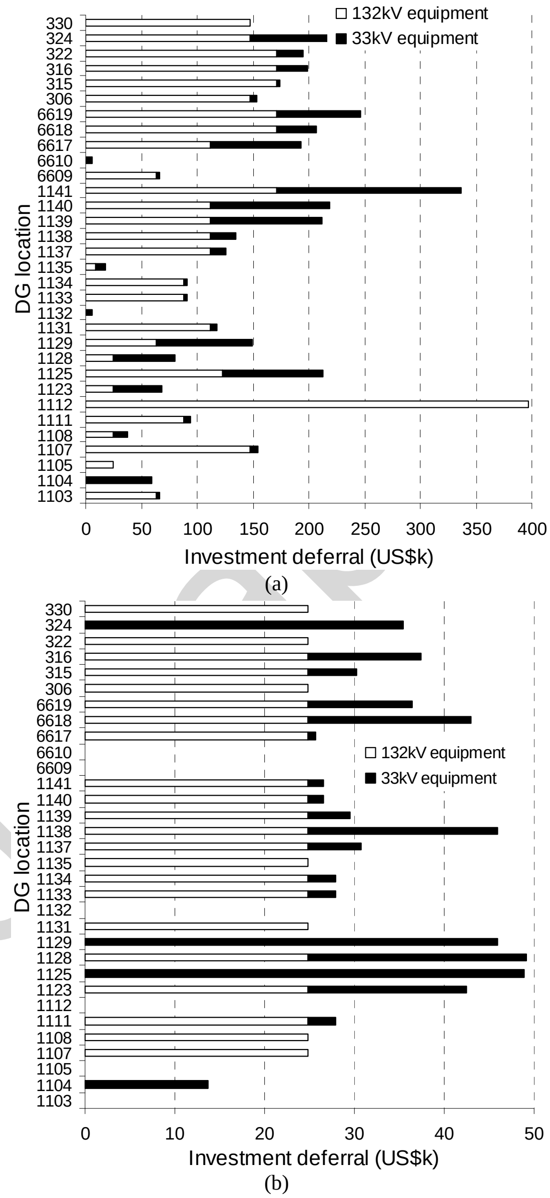

Fig. 4 Investment deferred by a 10MW (a) CHP with 69% F-factor, (b) wind farm with 24% F-factor across different locations.

deferment of 132kV reinforcements, when compared to CHP connected at those buses.

D. Impact of the F-factor

The level of security contribution provided by a DG plant has a major impact on the investment that could be deferred. It is possible, however, that for a given (nominal) DG capacity, a smaller F-factor produces greater benefit. This is the case when larger DG capacities lead to network constraints during first circuit outages, suggesting the need for DG-driven upgrades. Fig. 5 shows the results of the 10MW DG plant connected at bus 1135 (far right of

Fig. 3), considering separately CHP and wind power. Here, the CHP plant deferred US$17.5k, whereas with the wind farm almost US$25k worth of reinforcements was postponed.

During the loss of 132kV line 108-110, extra power flows through 33kV lines 313-318 and 336-312 to support the loads on the right hand side area of the network. This contingency results in an overload of line 313-318. Therefore, any capacity contribution from the DG unit at bus 1135 alleviates the power flows, deferring the investment schedule of an extra line 313-318. However, under the outage of line 103-105, power will flow from bus 312 to bus 336. If the capacity contribution of the DG at bus 1135 is greater than its local load (4.5MW), then additional power will also flow through line 312-336. As a consequence, due to this contingency, the CHP plant requires an additional line 103-105 to be commissioned earlier than the case without DG.

To understand how sensitive the schedule of reinforcements and investment deferral are in relation to the capacity contribution of a given DG connection, the F-factor of the 10MW generator at bus 1135 is varied. Fig. 6 shows that a capacity contribution above 4MW, i.e., F-factor more than 40%, reduces the ability to defer reinforcements, and bringing forward the need of a new line 103-105. As the F-factor increases beyond 80%, it in fact imposes net economic losses to the network as a result of the DG-driven reinforcement.

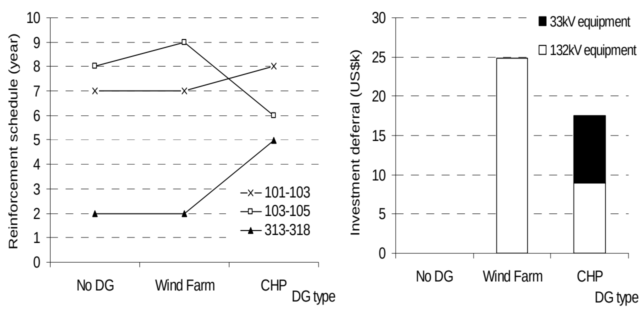

Fig. 5 Schedule of reinforcements (Left) and investment deferred (right) by a 10MW CHP and wind farm connected to bus 1135.

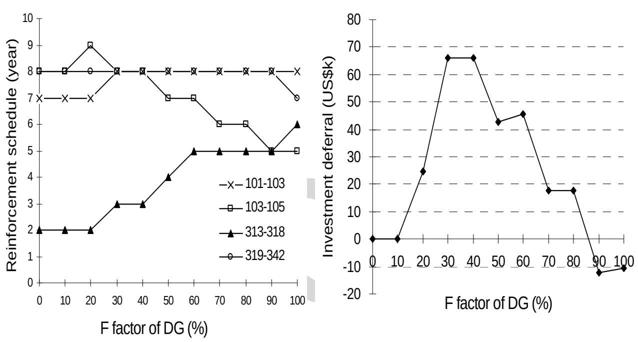

Fig. 6 Varying the F-factor of a 10MW DG plant connected to bus 1135. (Left) Schedule of reinforcements and (Right) investment deferred.

The total investment deferral produced by the connection of a single 10MW DG plant is presented in Fig. 7, considering the contribution factors of CHP, wind power and a hypothetical perfectly reliable unit (100% F-factor). In a similar manner to bus 1135, larger security contributions from a DG unit connected at bus 306 does not result in more investment being deferred. DG at buses 1132 and 6610 would also yield very little investment deferral regardless of the F-factors. Nonetheless, many locations do show substantial deferral of reinforcements with higher security contributions, as is the case of CHP against wind power.

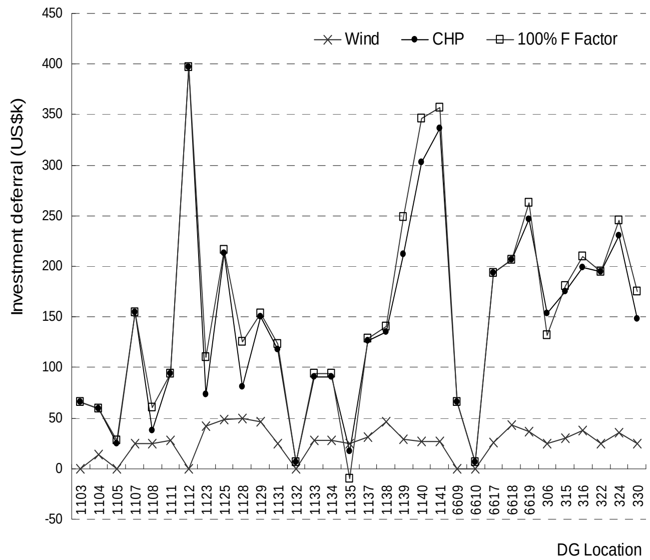

Fig. 7 Range of potential investment deferral obtained per MW increases of DG at different locations.

E. Strategy to Maximise the Investment Deferral

Provided that DNOs are capable of (or can influence) the schedule of deployment, size and location of DG units, it would be valuable to have a strategy that maximises the investment deferral. Here, a simple sensitivity analysis is used to find the minimum DG penetration required to achieve this, focusing on the security-related planning requirements where major deferments can be achieved.

Starting with those locations where a DG connection is able to defer the most expensive reinforcements (e.g., bus 1112 due to transformer T112-1112), the capacity contribution from the generation unit is continuously incremented by 1MW until no additional reinforcements are deferred. The same process is repeated for the DG plant at the next most beneficial location and so on (Step 1, Table IV). Then for each DG technology, the corresponding F-factor determines the net declared capacities required (Step 2). While this approach clearly would not result in a globally optimal solution it illustrates the idea. The results of this deployment strategy are shown in Table IV.

TABLE IV
DG DEPLOYMENT TO MAXIMIZE TOTAL BENEFITS

	Step 1	Step 2	
DG location	Capacity Contribution (during N-1)	Declared Capacity	
		CHP	Wind
	(MW)		
1112	7.0	10.14	29.17
1141	8.0	11.59	33.33
6618	5.0	7.25	20.83
6619	5.0	7.25	20.83
1111	5.0	7.25	20.83
1125	7.0	10.14	29.17

The maximum possible investment deferral would be achieved if all the reinforcements in Table III are postponed to year 10 or beyond, representing capital expenditure savings of around US$811k (28% of the total). Depending on the DG technology, the deployment strategy (in terms of capacity contribution) presented in Table IV is able to provide such gains. If all DG is assumed to be CHP, a capacity of 53.6MW would be required, representing a 36% DG penetration level (relative to peak load) during the base year. However, if the same capacity contribution is to be provided by wind farms the corresponding nominal capacities would exceed the thermal limits of the transformers (S_{max} of 10MVA), necessitating further reinforcements.

Without DG, the connection of line 311-337 (see Table III) has multiple functions. Firstly, it prevents the overloads of line 301-311 during the outage of line 312-333. Secondly, it also prevents overloading of line 312-336 when line 103-105 is tripped until the reinforcement of line 103-105 relieves this. When DG is strategically connected in this manner, one important observation is that the investment deferral does not simply depend on the location and size but also contingent on the existence of other DG developments. For instance, although DG units connected at and close to bus 1111 could effectively solve the first contingency scenario (disconnection of line 312-333), significant deferment only occurs when line 311-337 is no longer required during the second contingency (disconnection of line 103-105). To achieve this, capacity contributions of 8, 5 and 5MW are required at buses 1141, 6618 and 6619, respectively. These contributions are jointly capable of solving the second contingency and relieving the power flow through line 312-336 needed to support the demand in the left side of the network, and preventing its overloading even without the connection of line 311-337. In this case and regardless of the location, a single DG cannot be considered to defer investment in line 311-337 by itself; it is the *combination* of DG at the selected locations that could defer the connection of line 311-337 from year 0 to year 10.

V. Discussion

The analysis clearly demonstrates that DG can defer investment in network assets whether these are circuit or security driven. It also shows that the level of deferment that can arise depends strongly on the location and size of the DG. As such, analyses that assume investment deferral benefits are independent of DG location (e.g. [11, 12]), are over-simplified.

The security standard was a major driver of network upgrades and the level of security contributed assumed for the DG played a large role in allowing investment deferment. Despite the standard there is evidence that widespread recognition of the DG security contribution is lacking within UK DNOs. Confidence over the value of the security contributions could be one factor and improved location-specific figures (other than indicative ones) may be required. The prevailing planning culture or that currently networks are compliant without DG contribution may also explain this. However, with the potential for stricter regulatory efficiency targets implying continued downward pressure on DNO capital expenditure, it will be of increasing value for DNOs to integrate DG within the planning process.

Earlier work [11, 12] showed that recognition of the investment deferral benefits plays a crucial role in minimising apparent conflicts in deciding desirable penetrations of DG from the DNO and DG developer point-of-view. One of the premises behind this work was to characterise the range of benefits for DNOs. In jurisdictions where distribution companies can invest in DG the benefits can be realised directly. In other places like the European Union where unbundling rules preclude DNOs from owning DG, capturing such benefits is more subtle, relying on frameworks of incentives for developers and for DNOs themselves. The analysis provides an approximate means of valuing the locational benefit of DG capacity and could be used as the basis for connection or use of system charging.

The approach taken here with the successive elimination method and multistage planning is deliberately simple. Its rule-based approach mimics real planning processes and offers a clear audit trail. It also automatically handles the complexity inherent in meshed distribution networks taking it beyond simple feeder approaches. One criticism is that there is a mismatch in treatment of costs between the two stages of the analysis: successive elimination ranks the cost effectiveness without reference to the timing of the investments (i.e., discounting is ignored), while scheduling of the investments explicitly includes discounting. While this could have an impact where the cost effectiveness measures for two competing upgrades are very similar, there was no evidence here that it affected the outcome of the analysis.

The assessments shown here assume DG connections at the outset of the planning period which is driven by the need for reinforcement in the first year in this particular example. Additional insights may arise from exploring the influence of DG connection timing on deferment benefits.

Although an ‘optimal’ capacity was derived for this network the approach is not especially well suited to such applications. However, the idea of maximising benefits from deferred investment can be exploited using optimisation approaches; further work is planned on this.

The process as outlined and demonstrated here is deterministic and ignores the evident uncertainties surrounding planning. However, the relative simplicity of the approach means it could be extended to consider a range of scenarios for use in determining investment profiles.

VI. Conclusions

An approach for quantifying the impacts that DG may have on the deferment of demand- and system security-related network reinforcements was developed. The successive elimination technique along with a multistage planning analysis was adopted in order to determine the required investment (due to both demand growth and system security) and their corresponding scheduling. Knowledge of the required assets and their commissioning time along the planning horizon enables identification of those assets affected by the connection of DG, making it possible to obtain the corresponding new total investment cost.

Security of supply standards increase the need for reinforcements in distribution networks. Results demonstrated that significant benefits, in terms of investment deferral, can be harnessed if the capacity contribution of DG to system security is taken into account. Here, the more integrated approach for assessing the planning expansion problem clearly demonstrates that deferment varies with the location and size of the DG as well as the technology. It highlights the value for DNOs in integrating DG into the planning process.

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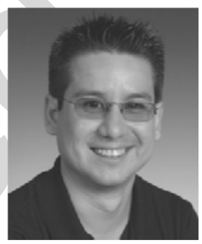

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