Optimal Planning of Distribution Network Access for Deferring Network Reinforcement

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Abstract—**Distribution network access is the procedure of connecting new demand and generation to the existing distribution network. Given the large numbers of distributed generators (DGs) requesting access of various capacities at different places, it is challenging for distribution network operators (DNOs) to decide how much the new generation and demand should be connected at each node, given a certain target of total amounts to be connected each year. In this paper, an optimal planning method of distribution network access is proposed to enable DNOs to decide the optimal amount of new demand and generation to be connected at each node across the network. The objective is to maximize the economic benefits of deferring future network reinforcement, by minimizing the net present value of the reinforcement investment given certain load and generation growth rates. The impact of the newly connected demand and generation on future reinforcement is modelled via a feasible operation region-based approach, considering both active and reactive power. Simulation results on a 13-node feeder selected from the 11kV UKGDS distribution system reveal the validity of the proposed method.**

Keywords—distribution network access, distributed generation, feasible operation region, network reinforcement deferral

I. Introduction

In the course of net-zero transition in electric power systems, there has been an increasing connection of low-carbon distributed energy sources (DERs) to distribution networks, such as rooftop photovoltaic panels, energy storage systems, electric vehicles, and flexible loads. The current access of these new demand and generation into distribution networks is allocated based on a first-come-first-served principle in most countries, like UK [1] and USA [2]. However, the conventional approach has become significantly inefficient with the increasing DERs connections, which results in very long connection queues in many countries, thus hindering the net-zero transition. For example, in the UK, the queue is dominated by renewables with 352GW till August 2024, which is far exceeding UK's energy needs for net zero [3]. In response to this situation, a more efficient approach for managing the connection must be investigated.

Many academic studies have therefore been conducted, proposing planning methods for managing the connection queues more efficiently. The objectives considered include minimizing the power exchange with the main grid [4], minimizing the power losses [5]-[8], enhancing the voltage profiles [5]-[7], [9], and maintaining the stability and reliability of power systems [10]. These methods enable DNOs to connect new demand and generation with minimal operating costs related to power losses and managing various network operating constraints. However, these operating costs only account for a very small percentage of the overall costs of DNOs. For example, in the UK, it is less than 4% of total DNO costs [11]. Therefore, more cost-reflective planning methods are needed for guiding DNOs to manage their connection queues.

The main question to be answered is which costs should be reflected. According to the practice in the UK, a breakdown of DNO's expenditure shows that the direct cost of network reinforcement and replacement accounts for 18.3% of DNO spend [11]. Due to the considerable cost in network reinforcement, deferring reinforcement of existing networks is a strategic priority for DNOs to achieve cost savings, high-efficiency utilization of existing assets, and even the reduction of environmental impact. This motivates us to propose an optimal planning method of distribution network access to defer future network reinforcement. Moreover, to the best knowledge, existing approaches for evaluating the economic benefits of network reinforcement deferral are mainly based on DC power flow, and assume one-way power flow considering only the load growth when evaluating the network headroom [12]-[15]. However, DC power flow is not accurate in distribution network analysis, and the assumption of one-way power flow may not be true with increasing connection of distribution generators (DGs) resulting in power flowing upwards.

To fill the research gaps, this paper presents a more cost-reflective method for planning the distribution network access to maximize the economic benefits of deferring network reinforcement. Specifically, the proposed method enables a DNO to decide how much new load and generation should be connected at each node of the distribution network for meeting the target of total annual connection amounts with the net present value of future reinforcement investment minimized. In the proposed method, the economic benefits of network reinforcement deferral are evaluated by a novel feasible operation region-based approach, considering both load and DG growth in a two-way power flow framework.

The rest of this paper is organized as follows. Section II presents an approach for evaluating the economic benefits of network reinforcement deferral. Section III elaborates on the optimal planning method for distribution network access. The case study is provided in Section IV. Finally, Section V summarizes the conclusions.

II. An Approach for Evaluating the Economic Benefits of Network Reinforcement Deferral

In this section, an approach for evaluating the economic benefits of network reinforcement deferral is introduced.

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Consider a distribution network $\mathcal{D}=(\mathbf{N},\mathbf{L})$ where there are N nodes indexed by $k\in\mathbf{N}$ and L network components (including power lines and transformers) indexed by $l\in\mathbf{L}$. The network $\mathcal{D}$ is operated by a DNO.

The net present value of future reinforcement investment is calculated. When the network reinforcement is deferred, the net present value of future reinforcement investment will decrease and can thus be used to quantify the economic benefits of network reinforcement. Specifically, future reinforcement investment in network component l can be discounted back to its present value PV_l (£), which will be a function of how far into the future the investment will be made. Assume the discount rate is d (%), then the present value of the future investment in n_l years will be

$$PV_l=\frac{C_l^{\text{Asset}}}{\left(1+d\right)^{n_l}},l\in\mathbf{L} \tag{1}$$

where C_l^{Asset} (£) is the modern equivalent asset cost (i.e. the cost for reinforcing the component l) and n_l (yr) is years away from the next reinforcement of component l.

The key step to obtaining the net present value is to calculating the number of years, after which the specified network component l has to be reinforced (i.e., to calculate n_l). Conventionally, the reinforcement is assumed to be implemented when the network component is fully utilized because of the load growth [12]-[15]. Assume a network component l has a capacity of Cap_l (MVA) and currently carries a power flow of D_l (MW). Also assume the load growth rate is r^{load} (%). Then the number of years n_l, which is needed for the network component l to reach its capacity (i.e., the carrying power flow increases from D_l to Cap_l, thus triggering the reinforcement) can be expressed as

$$n_l=\frac{\log Cap_l-\log D_l}{\log\left(1+r^{\text{load}}\right)} \tag{2}$$

which is derived from the following relationship:

$$Cap_l=D_l\left(1+r^{\text{load}}\right)^{n_l} \tag{3}$$

However, due to the rapid increase in DGs connected to distribution networks, the reinforcement of network components is dependent on both load growth and DG growth. More importantly, the formula (2) could be infeasible in some cases where power could flow upwards (i.e., $D_l\le 0$). Furthermore, the above conventional approach is based on DC power flow without considering reactive power flowing through the network component. Therefore, it is critical to propose a new method to find the relationship between the years to reinforce (i.e., n_l) and the real and reactive power flow through components, considering the growth in both load and generation connected to relevant nodes.

Specifically, if a network component l is required to be reinforced after n_l years, it will hit its thermal boundary:

$$\left(P_l^{\text{growth}}\right)^2+\left(Q_l^{\text{growth}}\right)^2=Cap_l^2,l\in\mathbf{L} \tag{4}$$

where P_l^{growth} (MW) and Q_l^{growth} (MVar) denote the real and reactive load flow through the component l with the increase in both load and generation connected to relevant nodes after n_l years. They can be explicitly expressed by the sum of net power injection connected to all downstream nodes of the component l, according to the feasible operation region method [16]:

$$P_l^{\text{growth}}=\sum\nolimits_{k\in\mathbf{N}}D_{l,k}P_{l,k}^{\text{net-growth}},l\in\mathbf{L},k\in\mathbf{N} \tag{5}$$

$$Q_l^{\text{growth}}=\sum\nolimits_{k\in\mathbf{N}}D_{l,k}Q_{l,k}^{\text{net-growth}},l\in\mathbf{L},k\in\mathbf{N} \tag{6}$$

where $D_{l,k}$ is a binary coefficient, which represents whether node k is the downstream nodes of the component l; $P_{l,k}^{\text{net-growth}}$ (MW) and $Q_{l,k}^{\text{net-growth}}$ (MVar) denotes the net real and reactive power injection to node k with the increase in load and generation after n_l years.

Further, if the load and generation growth rates are assumed as r^{load} (%) and r^{DG} (%) respectively, then the $P_{l,k}^{\text{net-growth}}$ can be calculated by the difference between the increase in load and generation:

$$\begin{aligned}P_{l,k}^{\text{net-growth}}&=P_{l,k}^{\text{load-growth}}-P_{l,k}^{\text{DG-growth}}\\&=P_k^{\text{load}}\left(1+r^{\text{load}}n_l\right)-P_k^{\text{DG}}\left(1+r^{\text{DG}}n_l\right),l\in\mathbf{L},k\in\mathbf{N}\end{aligned} \tag{7}$$

while $Q_{l,k}^{\text{net-growth}}$ can be calculated by $P_{l,k}^{\text{net-growth}}$ and the corresponding power factor:

$$Q_k^{\text{net-growth}}=\frac{P_k^{\text{net-growth}}}{\tan\varphi_k},k\in\mathbf{N} \tag{8}$$

where $P_{l,k}^{\text{load-growth}}$ and $P_{l,k}^{\text{DG-growth}}$ are the increase in load and generation of node k after n_l years; P_k^{load} (MW) and P_k^{DG} (MW) are current load and generation at the node k; φ_k denotes the power factor angle.

By solving equations (4)-(8), the years away from the next reinforcement of the component l, considering both load and DG growth and both active and reactive power flow, can be derived. Then, the present value of future reinforcement investments can be calculated by (1).

Note that there are three assumptions for the above calculation: 1) the approach for simulating power flow of the network, i.e. (5)-(6), ignores the power losses [16]; 2) the load and generation are assumed to grow in a linear way, with constant growth rates – this assumption is consistent with the statistics in the Future Energy Scenarios 2024 in the UK [17]; 3) the power factors are assumed constant across the network.

III. Optimal Planning of Distribution Network Access

In this section, an optimal planning method of distribution network access is proposed for a DNO for deferring the network reinforcement.

A. Model formulation

Suppose that the DNO targets at connecting certain amounts of new demand, i.e. $D^{\text{demand-access}}$ (MW), and new generation, i.e. $D^{\text{generation-access}}$ (MW) within one year. Then, the decisions of the DNO needs to be made are the optimal amounts of new demand $P_k^{\text{load-access}}$ (MW) and new generation $P_k^{\text{DG-access}}$ (MW) that should be connected to each node k for maximizing the economic benefits obtained from network reinforcement deferral. Note that the proposed model considers the "maximum load and maximum generation" scenario,

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which is one of the conventional scenarios commonly considered for demand-dominated distribution networks with reliable non-intermittent distributed generation.

Specifically, the objective function is formulated to minimize the sum of the present value of the future investment to reinforce the network components, formulated as

$$\min : C^{\text{reinforcement}} = \sum_{l\in\mathbf{L}} PV_l = \sum_{l\in\mathbf{L}} \frac{C_l^{\text{Asset}}}{(1+d)^{n_l}} \tag{9}$$

The relationship between n_l and the decisions variables $P_k^{\text{load-access}}$ (MW) and $P_k^{\text{DG-access}}$ (MW) can be expressed as

$$\begin{aligned} P_{l,k}^{\text{net-growth}} &= P_{l,k}^{\text{load-growth}} - P_{l,k}^{\text{DG-growth}} \\ &= \left(P_k^{\text{load}} + P_k^{\text{load-access}}\right)\left(1 + r^{\text{load}} n_l\right) \\ &\quad -\left(P_k^{\text{DG}} + P_k^{\text{DG-access}}\right)\left(1 + r^{\text{DG}} n_l\right), l \in \mathbf{L}, k \in \mathbf{N} \end{aligned} \tag{10}$$

by combining formulas (4)-(8) as presented in Section II.

In addition, all the thermal and voltage constraints of the network should be satisfied, after the connection of new demand and generation. Thus, the following constraints should also be considered:

$$(P_l)^2 + (Q_l)^2 \le Cap_l^2, l \in \mathbf{L} \tag{11}$$

$$P_l = \sum_{k\in\mathbf{N}} D_{l,k} P_k^{\text{net}}, l \in \mathbf{L}, k \in \mathbf{N} \tag{12}$$

$$Q_l = \sum_{k\in\mathbf{N}} D_{l,k} Q_l^{\text{net}}, l \in \mathbf{L}, k \in \mathbf{N} \tag{13}$$

$$\begin{aligned} P_k^{\text{net}} &= \left(P_k^{\text{load}} + P_k^{\text{load-access}}\right) \\ &\quad -\left(P_k^{\text{DG}} + P_k^{\text{DG-access}}\right), l \in \mathbf{L}, k \in \mathbf{N} \end{aligned} \tag{14}$$

$$Q_k^{\text{net}} = \frac{P_k^{\text{net}}}{\tan\varphi_k}, k \in \mathbf{N} \tag{15}$$

$$\begin{cases} \sum_{k'\in\mathbf{N}} \left(\alpha_{k,k'}^{\bar{V}} P_{k'}^{\text{net}} + \beta_{k,k'}^{\bar{V}} Q_{k'}^{\text{net}}\right) \le 1 \\ \sum_{k'\in\mathbf{N}} \left(\alpha_{k,k'}^{\underline{V}} P_{k'}^{\text{net}} + \beta_{k,k'}^{\underline{V}} Q_{k'}^{\text{net}}\right) \le 1 \end{cases}, k \in \mathbf{N}, k' \in \mathbf{N} \tag{16}$$

where $\alpha_{k,k'}^{\bar{V}}$, $\beta_{k,k'}^{\bar{V}}$, $\alpha_{k,k'}^{\underline{V}}$, and $\beta_{k,k'}^{\underline{V}}$ are the parameters for reformulating the voltage constraints, as detailed in [18]. Formulas (11)-(13) denote the thermal constraints. Formulas (14) and (15) represent the power injections to node k after connecting new demand and generation. Formula (16) denotes the voltage constraints of the network. Note that the connection of new load and generation, as our focus in this paper, can be viewed as one of the impacting factors on long-term voltage stability. In practice, the DNO will set the upper and lower limits of voltages across the network to maintain voltage stability. Thus, in our proposed model, the distribution network is required to operate within the feasible operation region after connecting new load and generation. That means the network will maintain long-term voltage stability based on our proposed method.

The total amounts of new demand and generation that are planned to be accessed equal to the sum of those of each node:

$$\sum_{k\in\mathbf{N}} P_k^{\text{load-access}} = D^{\text{demand-access}}, k \in \mathbf{N} \tag{17}$$

$$\sum_{k\in\mathbf{N}} P_k^{\text{DG-access}} = D^{\text{generation-access}}, k \in \mathbf{N} \tag{18}$$

Lastly, the range of the variables should be included in the optimization:

$$n_l \ge 0, l \in \mathbf{L} \tag{19}$$

$$P_k^{\text{load-access}} \ge 0, k \in \mathbf{N} \tag{20}$$

$$P_k^{\text{DG-access}} \ge 0, k \in \mathbf{N} \tag{21}$$

Formulas (19)-(21) ensure that variables n_l, $P_k^{\text{load-access}}$, and $P_k^{\text{DG-access}}$ are positive. Note that it is assumed that there is sufficient load and generation in the connection queue for each node (which is the case in the UK and many other areas in practice), and thus the upper bounds of $P_k^{\text{load-access}}$ and $P_k^{\text{DG-access}}$ are infinite. However, we can also set the upper bounds according to the total available demand and generation in the connection queue.

To sum up, the proposed optimization formulation for the DNO to decide the optimal distribution network access is as follows:

min: (9)
s.t. (4)-(8), (10)-(21).

The decision variables of the above optimization problem are the years after which the network reinforcement has to be conducted , n_l, and the amounts of new load and generation, $P_k^{\text{load-access}}$ and $P_k^{\text{DG-access}}$, to be connected the each node.

Note that the proposed model does not consider the power losses due to using the feasible operation region method to simulate the power flow model. This ignorance is acceptable in the problem we would like to address because the operating cost related to losses only account for a very small percentage of the overall cost of DNOs. In some cases, even though the losses are increased when using the proposed method to connect new load and generation to the network, the cost savings from network reinforcement deferral would be much more significant. The ignorance of losses will not influence the cost-reflectivity of the proposed method.

B. Solution method

The above optimization problem is a nonlinear programming problem. To deal with the nonlinear terms in the objective function, a set of inequality constraints are introduced to linearly approximate the objective function. Theoretically, the upper bound of n_l is infinite, but it is set as a big number defined as $\bar{n}_l$ (500 years in this paper) for simply the piecewise linearization. Considering a set of breakpoints $\left\{n_{l,m}^{\text{breakpoint}} \middle| n_{l,m}^{\text{breakpoint}} \in [0, \bar{n}_l], l \in \mathbf{L}, m \in \mathbf{M}^{\text{obj}}\right\}$, where $\mathbf{M}^{\text{obj}}$ is the number of breakpoints, then the objective function is transformed into

$$\min : C^{\text{reinforcement}} = \sum_{l\in\mathbf{L}} PV_l \tag{22}$$

$$PV_l \ge a_m^{\text{obj}} n_l + b_m^{\text{obj}}, l \in \mathbf{L}, m \in \mathbf{M}^{\text{obj}} \tag{23}$$

where a_m^{obj} and b_m^{obj} are linear coefficients.

In addition, regular polygons with 12 edges are used for the linearization of the quadratic expression in (4). Also, a set of binary variables $\left\{w_{l,m} \middle| l \in \mathbf{L}, m \in \mathbf{M}^{\text{thermal}}\right\}$ and two sets of continuous variables $\left\{P_{l,m}^{\text{growth}} \middle| l \in \mathbf{L}, m \in \mathbf{M}^{\text{thermal}}\right\}$, $\left\{Q_{l,m}^{\text{growth}} \middle| l \in \mathbf{L}, m \in \mathbf{M}^{\text{thermal}}\right\}$ are introduced. Then, the nonlinear equality constraint (4) can be approximated by

$$\sum_{m\in\mathbf{M}^{\text{thermal}}} w_{l,m} \begin{pmatrix} a_m^{\text{thermal}} P_l^{\text{growth}} \\ +b_m^{\text{thermal}} Q_l^{\text{growth}} + c_m^{\text{thermal}} Cap_l \end{pmatrix} = 0, l \in \mathbf{L}, m \in \mathbf{M}^{\text{thermal}} \tag{24}$$

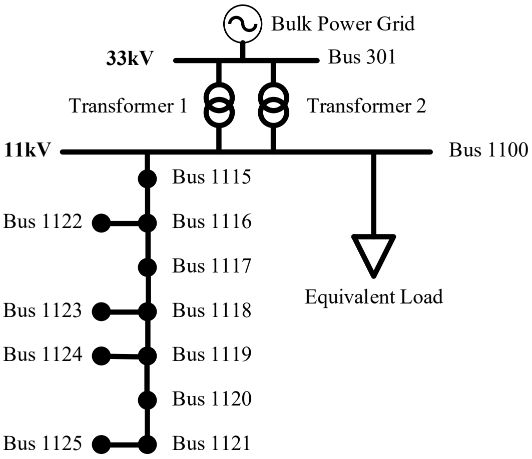

Fig. 1. The schematic diagram of the 13-node feeder selected from the 11kV UKGDS distribution system.

TABLE I
PARAMETERS OF THE COMPONENTS IN THE 13-NODE FEEDER.

fNode	tNode	Component	Asset cost (£)	Capacity (MVA)
301	1100	Transformer 1	2,011,429.00	26.40
301	1100	Transformer 2	2,011,429.00	26.40
1100	1115	Power line	99,220.00	8.86
1115	1116	Power line	99,220.00	8.86
1116	1117	Power line	99,220.00	8.86
1117	1118	Power line	99,220.00	8.86
1118	1119	Power line	99,220.00	8.86
1119	1120	Power line	99,220.00	8.86
1120	1121	Power line	99,220.00	8.86
1116	1122	Power line	22,550.00	4.84
1118	1123	Power line	22,550.00	4.84
1119	1124	Power line	22,550.00	4.84
1121	1125	Power line	22,550.00	4.84

(fNode and tNode represent the upstream and downstream node of a component, respectively)

$$\sum_{m\in\mathbf{M}^{\text{thermal}}} w_{l,m} = 1, l\in\mathbf{L}, m\in\mathbf{M}^{\text{thermal}} \tag{25}$$

$$\begin{cases} P_l^{\text{growth}} = \sum_{m\in\mathbf{M}^{\text{thermal}}} w_{l,m} P_{l,m}^{\text{thermal}} \\ Q_l^{\text{growth}} = \sum_{m\in\mathbf{M}^{\text{thermal}}} w_{l,m} Q_{l,m}^{\text{thermal}} \end{cases}, l\in\mathbf{L}, m\in\mathbf{M}^{\text{thermal}} \tag{26}$$

$$\begin{cases} \bar{\alpha}_m P_{l,m}^{\text{growth}} + \bar{\beta}_m Q_{l,m}^{\text{growth}} \le 0 \\ \underline{\alpha}_m P_{l,m}^{\text{growth}} + \underline{\beta}_m Q_{l,m}^{\text{growth}} \le 0 \end{cases}, l\in\mathbf{L}, m\in\mathbf{M}^{\text{thermal}} \tag{27}$$

where a_m^{thermal}, b_m^{thermal}, c_m^{thermal}, $\bar{\alpha}_m$, $\bar{\beta}_m$, $\underline{\alpha}_m$, and $\underline{\beta}_m$ are linear coefficients; $m\in\mathbf{M}^{\text{thermal}} = \{1,2,\cdots,12\}$ denotes piecewise index. Formulas (24)-(27) is the linear transformation of the constraint (4).

In order to ensure the proposed model could be solved more easily by mature solution tools, a set of slack variables $\{\varepsilon_{l,m}\in\mathbb{R}, l\in\mathbf{L}, m\in\mathbf{M}^{\text{thermal}}\}$ is introduced to further relax the equality constraints (24) and a set of auxiliary variables $\{y_{l,m} \mid y_{l,m}\ge\varepsilon_{l,m}, y_{l,m}\ge-\varepsilon_{l,m}\}$ are introduced to be a penalty added into the objective function. The constraint (24) is then transformed as

$$\sum_{m\in\mathbf{M}^{\text{thermal}}} w_{l,m}\begin{pmatrix} a_m^{\text{thermal}} P_l^{\text{growth}} \\ +b_m^{\text{thermal}} Q_l^{\text{growth}} + c_m^{\text{thermal}} Cap_l \end{pmatrix} + \varepsilon_{l,m} = 0 \\ , l\in\mathbf{L}, m\in\mathbf{M}^{\text{thermal}} \tag{28}$$

The objective function is transformed as

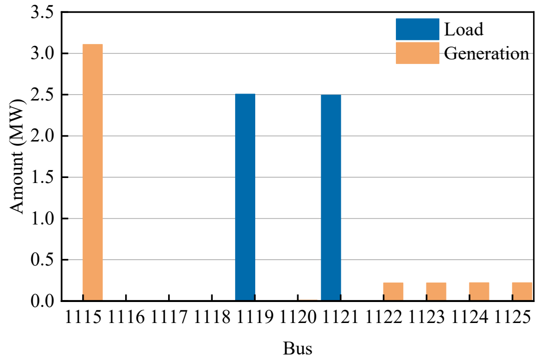

Fig. 2. Optimal planning results of distribution network access.

$$\min: C^{\text{reinforcement}} = \sum_{l\in\mathbf{L}}\left(PV_l + \sum_{m\in\mathbf{M}^{\text{thermal}}} w_{l,m} y_{l,m}\right) \tag{29}$$

After the above approximation, the optimization problem for planning the distribution network access is formulated as

min: (29)

s.t. (11)-(21),(23),(25)-(28)

which is a Mixed-Integer Quadratically Constrained Programming (MIQCP) problem and is then able to be solved by mature solution tools.

IV. CASE STUDIES

A 13-node feeder of an 11kV high-voltage underground network from the United Kingdom Generic Distribution System (UKGDS) was used for the case study. The computation of the case study was performed in MATLAB 2022a on a PC with an Intel(R) Core(TM) i7-9700 CPU @ 3.00 GHz processor and 16 GM RAM. The simulation was implemented in MATLAB/Yalmip environment, using Gurobi solver.

A. Simulation settings

The schematic diagram of the 13-node feeder selected from the 11kV UKGDS distribution system is shown in Fig. 1 and the load and generator distributions refers to [19]. The parameters of the components are shown in Table I.

The discount rate was considered as 6.9%, which is the commonly accepted Minimum Acceptable Rate of Return of UK's DNOs [15]. The load growth rate was set as 3.8% per year, and the DG growth rate was set as 11.4% per year, which were evaluated based on the data obtained from the Future Energy Scenarios 2024 [17].

Assume that the DNO aims to connect 5MW new load and 4MW generation in total within a year.

B. Result discussion

Fig. 2 gives the optimal planning results of the proposed method. The new demand is scheduled to be averagely accessed to the nodes 1119 and 1121 with 2.5MW. A majority of the generation (over 3MW) is scheduled to be accessed to node 1115 while the residual generation is averagely accessed to the nodes 1122, 1123, 1124, and 1125.

For further analysis, Table II gives the results of years away from the next reinforcement and the present value of future reinforcement investments. Since the equivalent load connected to the node 1100 accounts for a large percentage of the demand in the distribution network, a majority of generation is connected to the nearest node, i.e., Node 1115 to balance the demand to a maximum extent so that the present value of future reinforcement investments in the two transformers would be largely decreased. The residual generation

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is connected to the end nodes of the branches 1116-1122, 1118-1123, 1119-1124, and 1121-1125 to balance the demand locally as much as possible, since this will drive future investment to reinforce the corresponding network components to a minimum degree.

To illustrate the voltage stability of the network, the power flow of the distribution network is simulated. The upper and lower limits of voltage are defined as 0.95 (p.u.) and 1.05 (p.u.). The simulation results reveal that the voltage at all the nodes is around 1.02 (p.u.) and thereby the voltage stability can be maintained using our proposed method.

V. Conclusion

In this paper, a cost-reflective optimal planning method of distribution network access was proposed to enable DNOs to connect new demand and generation with the network reinforcement deferral. To assess the economic benefits of network reinforcement deferral, a more precise model was formulated for calculating the net present value of future reinforcement investments, considering both load growth and DG growth as well as both active and reactive power flow, via a feasible operation region-based method.

The case studies executed on a 13-node feeder selected from the 11kV UKGDS distribution system demonstrated the validity of the proposed method. The simulation results show that the proposed method can effectively guide the DNO to connect new demand and generation with maximum economic benefits of network reinforcement deferral.

Besides, the proposed method considers a conventional planning scenario in load-dominated distribution networks with conventional DGs. However, with the increasing penetration of renewable power generation and flexible loads (e.g., electric vehicles and heat pumps) subject to complex spatio-temporal characteristics, detailed load and generation profiles at each node of the network will need to be considered for the planning in the future.

What is more, although the proposed method enables DNOs to allocate the connection target of new demand and generation to each node in a more cost-reflective manner, this may not be entirely reasonable in practice. For example, some generation, which sits in the front of the connection queue may not be allocated with sufficient capacity if the proposed method is adopted. In this case, the DNO may need to pay some compensations. In the future, some new methods can be further investigated to integrate the advantages of the proposed method, in terms of economic benefits of network reinforcement deferral, and the conventional "first-come-first-served" principle, in terms of respecting the time order of new demand and generation proposals.

TABLE II
Evaluation of years away from the next reinforcement and present value of future reinforcement investments.

fNode	tNode	Component	n_l (yr)	PV_l (£)
301	1100	Transformer 1	21.06	121,048.44
301	1100	Transformer 2	21.06	121,048.44
1100	1115	Power line	9.04	54,297.40
1115	1116	Power line	23.74	20,350.65
1116	1117	Power line	45.78	4,676.81
1117	1118	Power line	29.20	14,135.54
1118	1119	Power line	100.50	121.41
1119	1120	Power line	500.00	0.00
1120	1121	Power line	45.00	4,923.23
1116	1122	Power line	500.00	0.00
1118	1123	Power line	500.00	0.00
1119	1124	Power line	500.00	0.00
1121	1125	Power line	500.00	0.00

(fNode and tNode represent the upstream and downstream node of a component, respectively)

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