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Distribution Network Capacity Assessment: Variable DG and Active Networks

Luis F. Ochoa, *Member, IEEE*, Chris J. Dent, *Member, IEEE*, and Gareth P. Harrison, *Member, IEEE*

Abstract—Increasing connection of variable distributed generation, like wind power, to distribution networks requires new control strategies to provide greater flexibility and use of existing network assets. Active Network Management (ANM) will play a major role in this but there is a continuing need to demonstrate the benefit in facilitating connection of new generation without the need for traditional reinforcements. This paper proposes a multi-period AC Optimal Power Flow (OPF)-based technique for evaluating the maximum capacity of new variable distributed generation able to be connected to a distribution network when ANM control strategies are in place. The ANM schemes embedded into the OPF include coordinated voltage control, adaptive power factor and energy curtailment. A generic UK medium voltage distribution network is analysed using coincident demand and wind availability data derived from hourly time-series. Results clearly show that very high penetration levels of new variable generation capacity can be achieved by considering ANM strategies compared to the widely used passive operation (i.e., ‘fit and forget’). The effects on network losses are also discussed.

Index Terms—Distributed generation, wind power, optimal power flow, active network management, distribution networks.

I. INTRODUCTION

INTEGRATION of renewable energy sources creates significant technical and economic challenges for Distribution Network Operators (DNOs) and developers. Despite potential benefits, such as reduction of losses or investment deferral [1-4], planning issues, the regulatory framework, and the availability of resources, have limited the DNOs and developers in their ability to accommodate distributed generation (DG).

Many of these difficulties relate to ‘fit-and-forget’ policies where ‘firm’ connections mandate that DG is able to output full capacity irrespective of network configuration. Assessment of connections focuses on worst-case network conditions, normally maximum generation at minimum demand. Whilst reasonable for firm energy sources, with variable renewables maximum generation may occur infrequently and the worst case situation tending to occur for a relatively small amount of

time. Firm connection would require that the DG capacity be restricted despite the opportunity for much higher energy production. The alternative is a ‘non-firm’ connection wherein the DNO may curtail the output of the renewable generator at low demand [5, 6]; this allows connection of larger generators but at the expense of lost production [5]. In addition to generator curtailment, the use of real-time control and communication systems forming an active network management (ANM) system may better integrate and exploit the different network assets and participants. Schemes such as coordinated voltage control, dynamic ratings, power factor control and automatic restoration can improve the controllability and reliability of the distribution network [5-9].

Despite being acknowledged by utilities and academics, and with a few notable implementations, such as the Orkney ANM scheme [6], ANM has not yet been deployed widely due to regulatory and commercial barriers [10, 11]. In part this is due to a need to justify investment in the control and communications infrastructure in terms of the benefits to the DNO and wider stakeholders. These include avoidance of primary asset investment, increased capacity of and production from renewable generation as well as reliability improvements. A key aspect of this process is gaining an understanding of the level of new renewable generation capacity that can be supported by the network without network upgrades (i.e., reinforcements) whilst maintaining operational limits. Indeed, a method to quantify the available capacity headroom would allow stakeholders to determine the most appropriate regulatory, commercial and technical strategies to better manage the distribution networks.

A better locational understanding of spare connection capacity can be obtained by a network capacity assessment [12-14]. The problem of adequately, or ‘optimally’, siting and sizing DG units has become the focus of a number of studies. Using techniques ranging from impact indexes [15-18] to analytical approaches [19, 20], and from metaheuristics [21-23] to linear [5, 24] and non-linear programming like AC Optimal Power Flow (OPF) [12-14, 25, 26], research has considered the impact of technical, economic and environmental aspects on the optimal placement of DG. Although some approaches found in the literature do to some extent consider the inherent time-varying behaviour of loads and (renewable) generation patterns [18, 23, 24, 27], there is an absence of methodologies that perform capacity assessments of variable renewable generation based on industry-accepted optimisation techniques such as OPF. Few

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have considered and accounted for the use of innovative network management schemes although a comparison of decentralised and centralised voltage control on optimal capacity was presented in [28] using a snapshot approach. A more sophisticated approach is essential when considering the use of generator curtailment wherein the ultimate viability of the renewable generator depends on the degree of curtailment.

Here, a multi-period AC Optimal Power Flow technique for evaluating network capacity for accommodating variable DG is proposed to offer a means of measuring the impact of ANM on connectable renewable capacity, and consequently increasing the harvesting of energy. In addition to effectively handling the time-variation of multiple renewable sites and demand, it also considers a range of active network techniques to allow maximum absorption of renewable generation capacity while respecting voltage statutory limits and thermal constraints. Active network management control algorithms including coordinated voltage control of transformers and voltage regulators, adaptive power factor control and energy curtailment are embedded within the formulation.

This paper is structured as follows: Section II presents the formulation of the multi-period AC OPF together with the inclusion of active network management. Section III illustrates a method for aggregating times-series generation and demand data and the application of the capacity assessment technique with a generic UK medium voltage distribution network. Results clearly show that very high penetration levels of new variable generation capacity can be achieved by considering ANM strategies compared to the widely used passive operation (i.e., ‘fit and forget’). The effects on network losses are also discussed. Finally, sections IV and V discuss and conclude the work.

II. PROBLEM FORMULATION

A. Multi-Period AC Optimal Power Flow

Network characteristics such as voltage and thermal limits, losses, topology, demand behaviour and potential locations for renewable developments, present a number of challenges when formulating the DG capacity allocation problem as a mathematical optimisation model. In [12-14], the ability and robustness of using AC OPF to maximise generation capacity and, therefore, identify available headroom was demonstrated, although only using a single, deterministic generation and demand scenario. Extending significantly the work presented in [29], the approach proposed here uses the non-linear programming (NLP) formulation of a multi-period AC OPF adapted to determine the maximum DG capacity able to be connected to a given network.

The objective of maximising DG capacity (and with it associated energy capture) within the physical limitations of the network and with economically sound levels of curtailment and capacity is entirely credible as the unbundled nature of the distribution business in Europe means that the DNO does not consider energy delivery beyond ensuring that the network can physically handle the power flows with acceptable reliability

and cost effectiveness.

The approach is based on reducing hourly time-series data to a set of scenarios where for each hour demand and generation potential is allocated to a series of bins (or ‘periods’, denoted by m). The inter-relationships between demand and generation potential are preserved with their joint probability defining the number of coincident hours (i.e., time duration, τ_m) over the year. Fig. 1 presents an example of how these multiple scenarios can be visualised with more detail given in Section III.A. True multi-periodicity is achieved by providing each scenario (m) with a different set of power flow variables whereas a unique, *inter-period* set of generation capacity variables (p_g) is used throughout the analysis. This is shown schematically in Fig. 2.

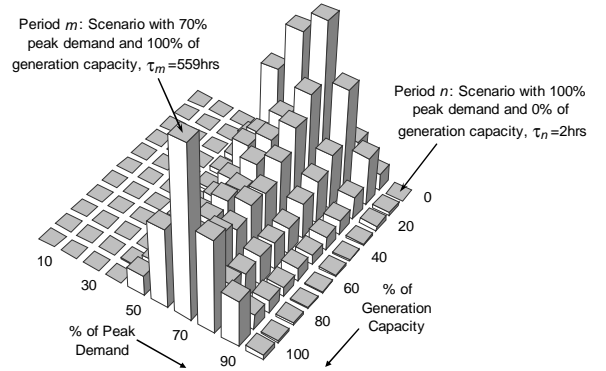


Fig. 1. Example multiple periods: coincident hours of demand and generation.

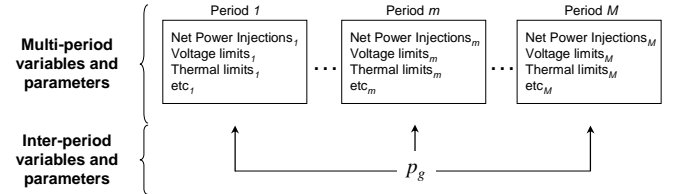


Fig. 2. Multi-period interdependency, where p is the total active capacity of generator g .

The basic multi-period AC OPF formulation maximises the total active DG capacity p of a set of generators G (indexed by g) across the set of periods M (indexed by m), according to the following objective function ($\forall m \in M$):

$$\max \sum_{g \in G} p_g \quad (1)$$

It is subject to a range of constraints. Voltages at bus b (B , set of buses) are constrained by max/min levels $V_b^{(+,-)}$:

$$V_b^- \leq V_{b,m} \leq V_b^+ \quad \forall b \in B \quad (2)$$

Constraints on the flow at each end of lines and transformers, l (L , set of lines):

$$\left(f_{l,m}^{(1,2),P}\right)^2 + \left(f_{l,m}^{(1,2),Q}\right)^2 = \left(f_l^+\right)^2 \quad \forall l \in L \quad (3)$$

where $f_{l,m}^{(1,2),P}$ and $f_{l,m}^{(1,2),Q}$ are the active and reactive power injections at each end of the branch (denoted 1 and 2) and f_l^+ is the apparent power flow limit on the branch (see Appendix for full formulation).

Kirchhoff's current law describes the active and reactive nodal power balance, $\forall b \in B$:

$$\sum_{l \in L | \beta_l^{1,2} = b} p_{b,m}^L + d_{b,m}^P \eta_m = \sum_{g \in G_b | \beta_g = b} p_g \omega_m + \sum_{x \in X | \beta_x = b} p_{x,m} \quad (4)$$

$$\sum_{l \in L | \beta_l^{1,2} = b} q_{b,m}^L + d_{b,m}^Q \eta_m = \sum_{g \in G_b | \beta_g = b} p_g \omega_m \tan(\phi_{g,m}) + \sum_{x \in X | \beta_x = b} q_{x,m} \quad (5)$$

Here, $(p, q)_{b,m}^L$ are the total power injections onto lines at b , i.e., $f_{l,m}^{1,(P,Q)} + f_{l,m}^{2,(P,Q)}$; and $d_{b,m}^{(P,Q)}$ are the peak active or reactive demands at same bus. In period m , η_m is the demand level relative to peak and ω_m is the generation level relative to nominal capacity as dictated by the variable (renewable) resource in that period. If required, the reactive power line injections (5) can be adapted to include shunt capacitance.

The distribution network has external connections at the Grid Supply Point (GSP) substation as well as interconnectors. Both can export power so the import/export constraints at the GSP or interconnector x (X , set of external sources), are:

$$\left. \begin{aligned} p_x^- &\leq p_{x,m} \leq p_x^+ \\ q_x^- &\leq q_{x,m} \leq q_x^+ \end{aligned} \right\} \quad \forall x \in X \quad (6)$$

The GSP is taken as the reference (slack) bus b_0 with the voltage angle set at zero, i.e., $\delta_{b_0,m} = 0$.

No capacity constraint is placed on the new DG units since the aim is to maximise their real power output. Fault level constraints are not considered here, but can also be implemented [26].

Generally speaking, the traditional (passive) network approach would set the substation secondary voltage to a fixed value (e.g., $V_{SS} = 1.03\text{pu}$), and operate DG units at constant power factors (e.g., $\cos(\phi_{g,m}) = 0.95$, leading or lagging) over all load conditions. In practice, DNOs may vary the target distribution voltage, often seasonally, but no dynamic behaviour occurs. With power factor, load conditions are taken into account in some countries but power factors remain at specific values or within ranges and is not actively dispatched.

B. Incorporating Active Network Management

With ANM, DNOs will be capable of optimising use of their assets by dispatching generation, controlling OLTCs and voltage regulators, managing reactive power, and reconfiguring the system [5, 8, 9]. Implementation of such schemes will require complex control techniques while the actual actuation of devices (e.g., tap changers) will depend on their respective response time-scales. As the proposed technique is designed for use at the planning stage, it is assumed that network components respond immediately to control actions, and have effectively one (steady) state in each period (m). Thus, in addition to network constraints traditionally used in AC OPF formulations (e.g., voltage and thermal limits), variables and constraints derived from ANM schemes must also be incorporated in the method:

1) Coordinated Voltage Control (CVC)

By dynamically controlling the OLTC at the substation and

the corresponding distribution secondary voltage, more DG capacity might be connected [5]. Thus, in each period the secondary voltage of the OLTC will be treated as a variable, rather than a fixed parameter, while maintaining its value within the statutory range:

$$V_{b_{OLTC}}^- \leq V_{b_{OLTC},m} \leq V_{b_{OLTC}}^+ \quad (7)$$

2) Adaptive Power Factor Control (PFc)

Depending on the technology utilised by the distributed generator, operation at leading, unity or lagging power factors is feasible. (For clarity, terms *leading* and *lagging* will be replaced in the text hereafter by *capacitive*, where reactive power is injected by the generator, and *inductive* power factors, respectively). However, the ability of DG units to offer 'dispatchable' or adaptive power factor control will ultimately rely on the existence of an appropriate ancillary service market or through requirements in the connection agreement. Here, it is envisaged that DG provides such a scheme with the power angle of each generator, $\phi_{g,m}$, considered as a variable. In practice DG will be required to operate within a certain range of power factors ($\phi_{g,m}^{(+,-)}$); the following constraint applies:

$$\phi_g^- \leq \phi_{g,m} \leq \phi_g^+ \quad (8)$$

3) Energy Curtailment

The network characteristics and wind power patterns may result in voltage and thermal limits restricting DG capacity in other cases at minimum demand or at other times. Curtailment of the DG active power output is an option to alleviate such problems [5, 30]. Power curtailment is formulated here by adding a negative generation (or positive demand) variable ($p_{g,m}^{curt}$) at the same location of each DG unit; solely affecting the constraints related to active and reactive nodal power balance. Thus, (4) and (5) are, adapted by adding terms $\sum_{g \in G_b} p_{g,m}^{curt}$ and $\sum_{g \in G_b} p_{g,m}^{curt} \tan(\phi_{g,m})$, respectively.

In general, limiting the power production of DG units requires appropriate DNO and regulatory policies to allow non-firm commercial arrangements and will ultimately be assessed by developers on economic grounds. To examine the impact of different allowed levels of curtailment on overall DG capacity, the total amount of curtailed energy from each DG will be restricted to a curtailment factor λ_{curt} , a percentage of the potential energy that could have otherwise been delivered by each DG. The following constraint follows:

$$\sum_{m \in M} p_{g,m}^{curt} \tau_m \leq \lambda_{curt} \left[\sum_{m \in M} p_g \omega_m \tau_m \right] \quad \forall g \in G \quad (9)$$

where τ_m is the duration of period m . The curtailment variables $p_{g,m}^{curt}$ need to be limited to the output of g at the corresponding period:

$$p_{g,m}^{curt} \leq \omega_m p_g \quad \forall g \in G \quad (10)$$

C. Implementation

The method was coded in the AIMMS optimisation modelling environment [31] and solved using the CONOPT

3.14A NLP solver.

III. CASE STUDY

In this section the multi-period AC OPF technique is applied to a generic UK distribution network. First, the method for aggregating times-series generation and demand data from single and multiple sources is detailed. Next, in order to demonstrate the method as a DG capacity analysis tool, a simplified version of the network is studied with only a single DG unit connected. Subsequently, and increasing the complexity, the ability of the technique to determine capacity across several DG units is also investigated by considering the full network and two different wind power profiles. Finally, the computational performance is briefly discussed.

A. Time-varying Generation and Demand

A sample of the hourly demand for central Scotland in 2003 is shown in Fig. 3 [32] along with coincident wind production of two different wind sites (named here, WP1 and WP2). The wind production data was derived from UK Meteorological Office measured wind speed data and have been processed and applied to a generic wind power curve [32]. While for demand there is a clear seasonal and diurnal pattern, for wind the pattern is less clear, although it tends to be more significant in winter months. Moreover, due to the geographic correlation of the studied wind profiles, the potential for wind power production is to certain extent similar. However, from Fig. 3 it is evident that particular (and sometimes critical) demand/wind scenarios could be lost if only one wind profile is adopted.

One way to reduce the computational burden of a full time-series analysis is to use aggregate wind availability and demand into a manageable number of wind/demand scenarios based on their joint probability of occurrence. The ‘duration’ of each scenario is then the number of coincident hours which it represents.

Considering the first wind profile WP1 alone, Fig. 4 presents the coincident hours for each of the scenarios used here. It breaks the demand and generation series into a series of bins: to illustrate the process, 10 ranges for demand (e.g., $[0,10\%]$, $(10\%,20\%]$,...) and 11 ranges for generation (e.g., $\{0\}$, $(0,10\%]$, $(10\%,20\%]$,...) are used. With demand never below 0.35pu (during summer), only 74 non-zero scenarios are effectively considered in the analysis (Fig. 4, right). Due to the aggregation process (using the upper values of the adopted demand scenarios), both the capacity factor of the wind data and the load factor of demand increased from 0.41 to 0.45, and from 0.63 to 0.68, respectively.

In this particular case, Fig. 4 shows that most of the time generation levels are relatively low. This could imply that only large wind power capacities would be able to offset significant amounts of load. Low demand (40%) and high wind availability (60 to 100%) present relatively few coincident hours. Therefore, as for firm connections if only worst case scenarios are assumed such as minimum demand-maximum generation, generation capacity could be constrained more than is necessary.

The method is able to cater for more than one type of resource. To illustrate this, the second wind profile (WP2) is now also considered. The extra wind profile requires the aggregation of demand/generation levels to be re-calculated based on their mutual joint probability. As shown in Fig. 5 (left), for each range of generation capacity of the first wind profile, a ‘layer’ with the coincident hours of demand/generation is created for the second wind power profile. Although this approach may seem to create a large number of demand/generation scenarios, due to the geographical correlation of the wind data used here, only 146 periods contain non-zero number of hours. Fig. 5 (right) shows this. For WP2 the capacity factor increased from 0.48 to 0.52.

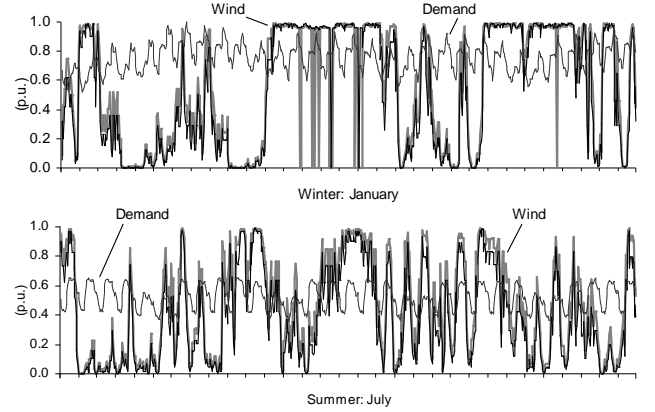


Fig. 3. Winter (top) and Summer (bottom) hourly demand and wind power production (relative to peak) for central Scotland, 2003 [32]. Two different wind profiles are considered: WP1 (black line) and WP2 (grey line).

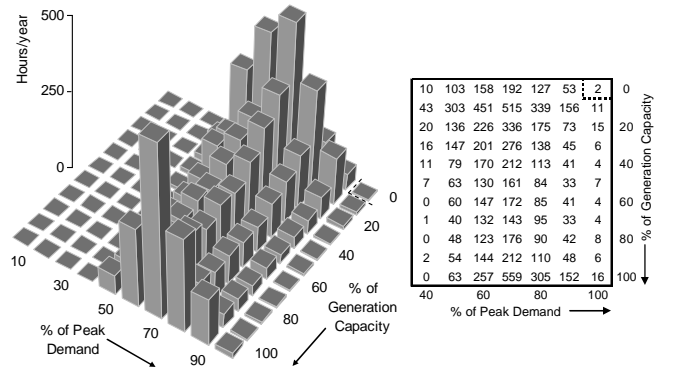


Fig. 4. Coincident hours for each of the demand/generation scenarios.

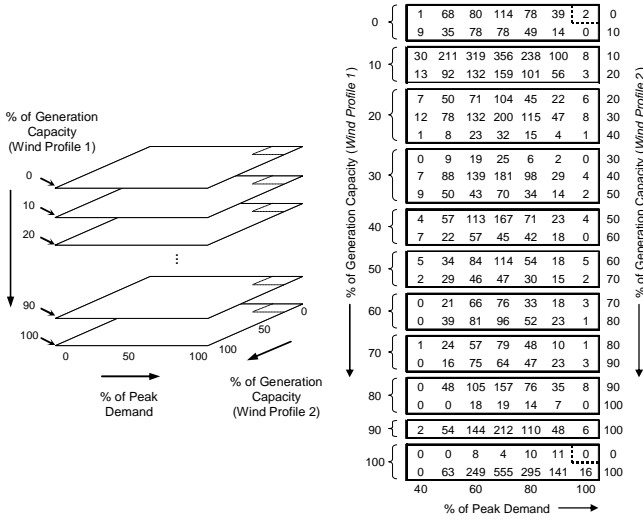


Fig. 5. Schematic example of how the coincident hours are obtained for the two wind profiles (left) and coincident hours for each of the scenarios (right).

The extra resource requires a set of new generators in the formulation, G_2 indexed by g_2 , to be included, requiring new variables and parameters similar to those for set G (e.g., β_{g_2} , $\phi_{g_2,m}$, $\omega_{2,m}$). The objective function (1) and the corresponding constraints (4)-(5), (8)-(10) are updated accordingly. It should be noted that the new set of generators does not necessarily affect the processing time of the method. The number of scenarios and network elements (lines, OLTCs, interconnector, etc.) will have a more significant impact.

It is important to highlight that the analysis of coincident hours can be extended to any energy mix including conventional (e.g., CHP, hydroelectric) and renewable (e.g., wave power, tidal current power) sources.

B. Simplified EHV1 Network – Single DG

The first analysis considers the connectable capacity of a wind farm in a simple network. Fig. 6 shows the Simplified EHV1 Network from the UK Generic Distribution System (GDS). Full data for this 16-bus 33kV rural weakly meshed network is available in [33]. The feeders are supplied by two identical 30MVA 132/33kV transformers. The GSP voltage is assumed to be nominal. In the demand-only case (no DG), the OLTC at the substation has a target voltage of 1.036pu at the secondary. A voltage regulator (VR) is located between buses 8 and 9, with the latter having a target voltage of 1.03pu. Voltage limits are $\pm 6\%$ of nominal, reflecting UK practice. A single DG unit is located at bus 16 driven by the aggregated wind profile WP1. The total peak demand is 38.2MW. In the demand-only case (using the aggregated demand profiles from Fig. 4) the annual demand is 229GWh with losses at 3.9%.

The demand/wind scenarios from Fig. 4 along with a range of passive and progressively more active network management schemes were applied to the network. The maximum wind power capacity that can be accommodated at node 16 was investigated considering: the coordinated voltage control (CVC) of the OLTC and the voltage regulator; adaptive power factor control (PFc); and different maximum levels of

curtailment. The passive management case is referred to as ‘no CVC’. The corresponding results are presented in Fig. 7.

The coincidence of minimum demand and maximum generation is normally regarded as the ‘worst case’ scenario for voltage rise in the DG feeder and therefore the main constraint on capacity. In this particular network, however, it is during maximum demand conditions that low voltages at the end of the feeder without DG (buses 11 and 12) prevent the voltage at the busbar (bus 2) being set too low. As such, there is a restriction on the ability of coordinated voltage control of the OLTC and VR, to significantly increase the connectable DG capacity above the passive management case. The limitation on voltage regulation also influences the effectiveness of adaptive power factor control, although progressively more inductive power factor allows more DG capacity by restricting DG feeder voltage rise. Despite the limitations imposed by the network, for the single DG unit, the combination of CVC and PFc allows a DG penetration of 15% relative to peak demand. This represents capacity increase of over 50% over the passive management case.

It can be seen in Fig. 7 that the cases that employ curtailment of the wind production have much more generation capacity able to be connected. This is achieved by constraining generator output at maximum demand and other key conditions whilst maximising production at other times. Together with the CVC and PFc schemes, a 2% limit on energy curtailment almost doubles the wind power capacity reaching 29% penetration, and this figure goes up to 41% when the curtailment limit is set to 10%. These represent three to four times more network capacity than passive management.

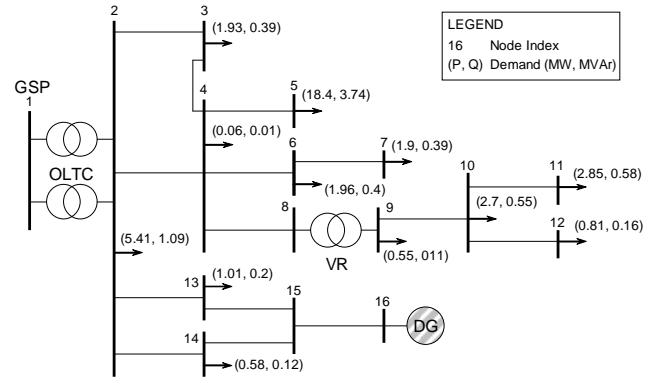


Fig. 6. UK GDS Simplified EHV1 Network [33] at maximum load.

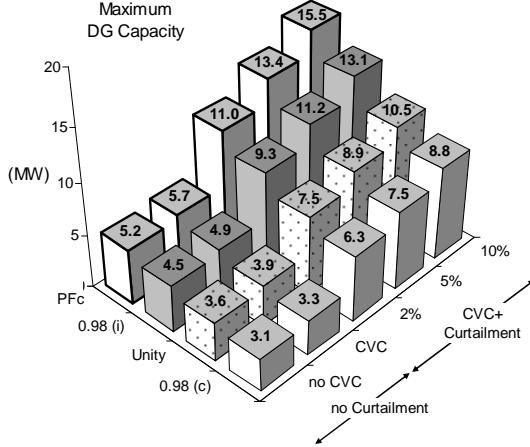


Fig. 7. Simplified EHV1 Network: Connectable DG capacity (in MW) with ANM strategies (c: capacitive, i: inductive, and PFC: adaptive power factor control).

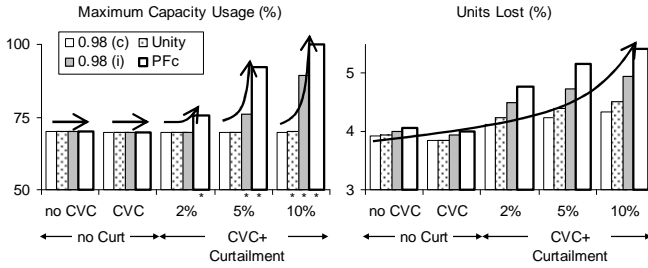


Fig. 8. Maximum loading of the branches (left) and losses (right) for the cases in Fig. 7. Maximum capacity usage corresponds to the GSP transformers, except * which refers to line 15-16.

The impact of the combinations of ANM schemes on the usage of the most heavily loaded transformer or line is shown in Fig. 8 (left). At times of zero wind power and peak demand, 70% of the GSP transformer capacity is used. However, at greater DG capacities, the line connecting the wind farm reaches its maximum transfer capacity. As for losses, Fig. 8 (right), it is clear that these increase at higher DG penetrations. With curtailment, losses exceed the demand-only case.

C. Full EHV1 Network – Multiple DG and Resources

The analysis is now extended to the full EHV1 network (Fig. 9) for multiple generators and multiple resources. Specific data for the 61-bus 33/11kV weakly meshed network is available in [33] and much of the operating setup is identical to the simplified network (e.g., GSP transformer capacity and VR voltage). The interconnector, treated as a PV bus, has a target voltage of 1.00pu and is able to provide/absorb 15MVA. In the original demand-only case, the OLTC at the substation has a target voltage of 1.045pu at the secondary bus. The OLTCs on the 33/11kV distribution transformers have a target voltage of 1.03pu (to ensure supply on the rural 11kV feeders within voltage limits). While the same demand characteristics apply, the losses in the demand-only case are 4.9%, comparable with typical UK rural networks.

Six wind generation sites are available. Three (buses 1105, 1106, 1108) are considered sufficiently close geographically to all use the WP1 profile. The network contains a subsea cable

(line 318-304) connecting the ‘mainland’ with an island on which the other three sites lie (1113, 1114, 1115). These are close together and enjoy approximately the same wind resource but this is sufficiently distinct to that on the mainland to require the use of the second wind power profile (WP2).

The simulations were re-run for this more complex situation using the multi-resource demand/generation scenarios (Fig. 5, right). The aggregate DG capacity that can be connected to the six sites has been evaluated for all control modes and the results are shown in Fig. 10. Due to the number of potential locations and their corresponding proximity to loads, relatively high values of connectable DG capacity were found. The major capacity constraints imposed by low voltages on the parallel feeders experienced in the single DG example are not as obvious in this example as there is DG on most of the feeders helping raise overall voltages. It is clear that the greater flexibility offered by adaptive power flow control leads to the largest wind power generation capacities in all cases. Without coordinated voltage control (‘no CVC’ case), PFC alone allows a DG penetration of 85% relative to peak demand (an increase of around a fifth over passive management). The allowable penetration reaches 103% when applying CVC, while curtailment, permits progressively greater integration of wind capacity, reaching 118% penetration for a limit of 2% and 143% at the 10% curtailment level (i.e., doubling capacity).

Fig. 11 presents a breakdown of the connectable generation capacity across the six sites. The impact of using coordinated voltage control and adaptive power factor control on the available capacity of each location is evident. In the passive management case with fixed 0.98 capacitive power factor, more than 73% of the total capacity is sited on the mainland (1108, 1106 and 1105). Adopting the CVC and PFC schemes, however, it is possible to make much more capacity available on the island, increasing it by almost three-fold to a 46% share of the total capacity. There are two main reasons why the mainland is allocated with more DG capacity:

1. The higher capacity factor of the wind profile used for the DG units on the island means that less generation capacity is required to meet the local demand and to reach the thermal limits of lines and transformers.
2. The local load on the mainland is larger than that for the island area, allowing more capacity to be connected.

In most cases, the limiting factor was the thermal limit of 33/11kV transformers at the DG connection nodes; reinforcement would be essential for further integration.

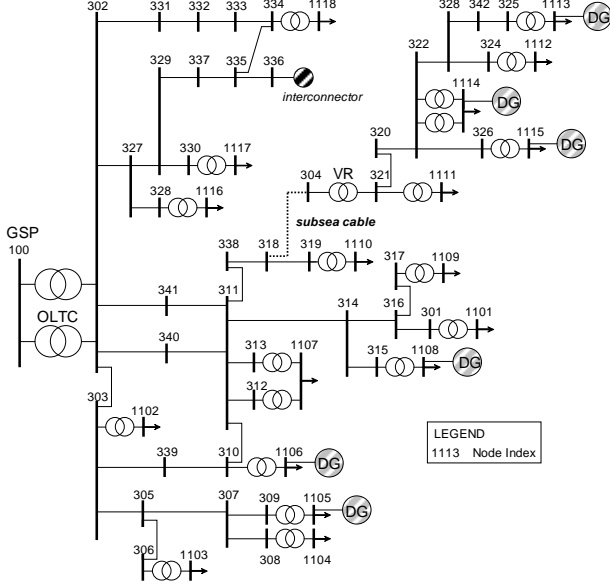


Fig. 9. UK GDS EHV1 Network [33] and potential locations for distributed wind power generation.

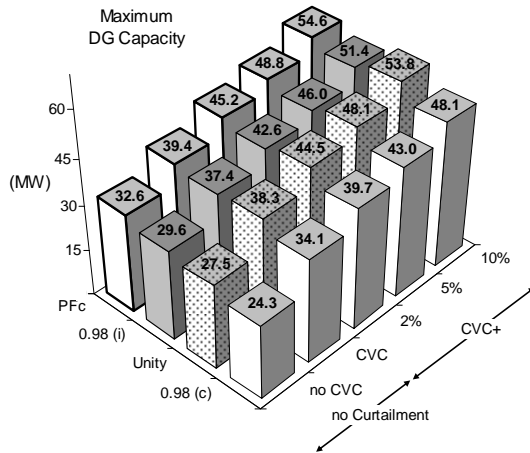


Fig. 10. Full EHV 1 Network: Connectable DG capacity (in MW) with ANM strategies (c: capacitive, i: inductive, and PFC: adaptive power factor control).

Fig. 11 also allows examination of the impact of ANM schemes on the specific capacity available at each site. There are a range of capacities at different buses ranging from zero to around 10MW for the cases shown. Across these cases, the capacity at several buses, e.g., 1106, remains similar, while that at bus 1115 changes significantly, as progressively more ANM is applied, up to the point where its transformer thermal limit is reached. This suggests that ANM will benefit otherwise marginal sites more than others.

As with the simplified network, energy losses increase significantly due to the large volumes of generation being exported to the transmission grid, particularly under fixed inductive power factors. Fig. 12 (left) shows the annual losses which tend to easily surpass the demand-only case.

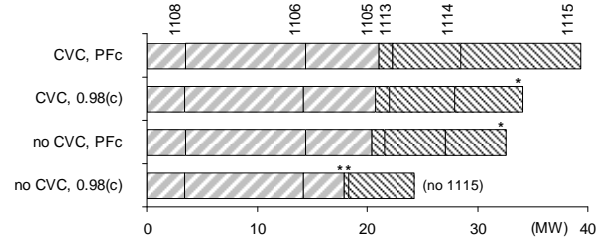


Fig. 11. Locational breakdown of available DG capacity across the sites. Except for *, 33/11kV transformers at the DG connection nodes reached their thermal limits.

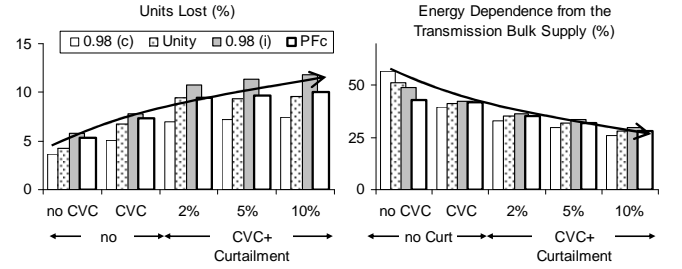


Fig. 12. Percentage losses (left) and dependence on the GSP supply (right) where the demand-only case represents 100% dependence.

D. Computational Performance

In terms of processing time, each case for the simplified network were delivered in around 30 seconds (on a PC, Intel Core2 2.13GHz, 2.00GB of RAM). The increased complexity of the full network (e.g., buses, number of scenarios, etc.) raises the duration to approximately 30 minutes per case.

IV. DISCUSSION

A. Application and Limitations

The multi-period AC OPF offers a coherent and robust method of defining available capacity of distribution networks for connecting variable generation. The combination of this together with the embedded active network management schemes are believed to make it a unique tool. Its application demonstrates some of the benefits of ANM while quantifying areas of concern like losses and it may be applied to examine the cost-benefit of differing combinations of ANM between decentralised and more extensive systems based around extensive communications and centralised control.

The method has been designed primarily for distribution systems but is generic as it can handle both meshed and radial networks. It is also applicable at transmission level, for example, looking at constraint volumes across boundaries. This may be valuable as the two systems become more interdependent and evaluation of DG export and control becomes more of an issue for transmission systems at higher renewable penetrations.

One limitation on the realism of the examples is the granularity of the bins used to determine the coincident generation and demand periods. Here a 10% interval was used for simplicity but the resolution can be increased albeit at the expense of greater numbers of coincident periods and slower processing. This is not likely to be a significant issue for

smaller systems but may pose a challenge for larger systems. Further work on this aspect is planned.

Here two separate wind profiles were demonstrated although ultimately any combination of resources is feasible. However, as further and different generation profiles are employed the challenge of correctly representing their correlations grows [34] along with the number of coincident periods and consequent processing requirement. Again further work is planned on this.

B. Non-firm Connection

The analysis presented here is optimal from the overall network point of view. However, it does not distinguish between sites in terms of their financial tolerance of curtailment and does not consider overall maximisation of energy capture. Further it does not consider the issue of curtailment priority within some ANM schemes that use order of connection to dictate last-in-first-out rules for non-firm connection [34]. These are important areas for research and it is believed that the framework offers a sound basis for tackling them.

C. Commercial Arrangements and Regulation

Although the ANM schemes presented here demonstrate a significant impact on potential connection volumes, their implementation will depend on specific commercial arrangements and appropriate regulatory incentives. For example, DNOs earn a return on their assets but with ANM no additional primary assets are required, implying a disincentive for ANM schemes. In incentive-based regulatory frameworks the issue of higher losses under ANM is another important consideration as a defined loss reduction incentive may penalise DNOs as a result of greater DG penetration. In the UK, wind power generally offsets energy supplied by the predominantly fossil-fuelled transmission network. Therefore there is also an argument that as ANM delivers environmental benefits through greater renewable penetration (see Fig. 12, right) this should be recognised explicitly in DNO incentives for active network management.

V. CONCLUSIONS

This paper proposes a novel, flexible multi-period AC OPF-based technique able to determine the maximum connectable capacity for variable (renewable) generation under a range of active network management (ANM) schemes including coordinated voltage control, adaptive power factor control and energy curtailment. Results clearly show that, compared to the widely used passive operation of distribution networks, very high penetration levels of new variable generation capacity can be reached by strategically adopting ANM schemes.

ANM is regarded as a key means of increasing the ability of distribution networks to accommodate variable generation. The proposed tool allows quantification of the benefits in terms of the ability of ANM schemes to 'free up' capacity, and thus, help justify the corresponding investment.

It is important, however, to understand that the several technical benefits that ANM schemes bring about must be assessed in a case-by-case basis since network and renewable sources characteristics drive the performance and cost-effectiveness of each scheme.

VI. APPENDIX

The real and reactive power flow injections onto the start and end buses of each line l , are calculated with the following.

At the start bus of lines, $\forall l \in L$ and $\forall m \in M$:

$$f_{l,m}^{1,P} = g_l \cdot V_{\beta_l^1,m}^2 - V_{\beta_l^1,m} \cdot V_{\beta_l^2,m} \cdot \left[g_l \cdot \cos(\delta_{\beta_l^1,m} - \delta_{\beta_l^2,m}) + b_l \cdot \sin(\delta_{\beta_l^1,m} - \delta_{\beta_l^2,m}) \right] \quad (11)$$

$$f_{l,m}^{1,Q} = -b_l \cdot V_{\beta_l^1,m}^2 - V_{\beta_l^1,m} \cdot V_{\beta_l^2,m} \cdot \left[g_l \cdot \sin(\delta_{\beta_l^1,m} - \delta_{\beta_l^2,m}) - b_l \cdot \cos(\delta_{\beta_l^1,m} - \delta_{\beta_l^2,m}) \right] \quad (12)$$

At the end bus of lines, $\forall l \in L$ and $\forall m \in M$:

$$f_{l,m}^{2,P} = g_l \cdot V_{\beta_l^2,m}^2 - V_{\beta_l^2,m} \cdot V_{\beta_l^1,m} \cdot \left[g_l \cdot \cos(\delta_{\beta_l^2,m} - \delta_{\beta_l^1,m}) + b_l \cdot \sin(\delta_{\beta_l^2,m} - \delta_{\beta_l^1,m}) \right] \quad (13)$$

$$f_{l,m}^{2,Q} = -b_l \cdot V_{\beta_l^2,m}^2 - V_{\beta_l^2,m} \cdot V_{\beta_l^1,m} \cdot \left[g_l \cdot \sin(\delta_{\beta_l^2,m} - \delta_{\beta_l^1,m}) - b_l \cdot \cos(\delta_{\beta_l^2,m} - \delta_{\beta_l^1,m}) \right] \quad (14)$$

where g_l and b_l are the conductance and susceptance of l , respectively; and $\delta_{b,m}$ is the voltage angle at b .

When tap changers capabilities exist in l (e.g., OLTCs, voltage regulators), the corresponding terms for the voltage at the start bus of the line, i.e., $V_{\beta_l^1,m}$, in (11) to (14) must be divided by $t_{l,m}$, whereas $t_l^- \leq t_{l,m} \leq t_l^+$.

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