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ORIGINAL RESEARCH

Flexible management and decarbonisation of rural networks using multi-functional battery control

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Abstract

To support the electrification of heat and transport, distribution network operators are looking to adopt network management solutions which can exploit local flexibility to advance their decarbonisation efforts in line with the evolving management requirements of the network. This paper develops a multi-functional battery control strategy that integrates constraint management with carbon-intensity linked control dispatch – carbon control – to support decarbonisation of rural distribution networks in Scotland by displacing last resort backup diesel generation and facilitating low carbon network balancing in the drive towards self-sustaining local distribution networks. The interplay between the different functionalities is considered to understand the challenges, and opportunities, of adopting multi-functional battery storage as an alternative management solution based on an operational distribution network in Scotland. Case studies are presented which consider network constraints at different times of day and year for various generation, demand and carbon intensity profiles to support this investigation. The findings of this work provide for the near-term, realisation of self-sustaining carbon-neutral local distribution networks that are in keeping with both the operational objectives of incumbent network operators, smart local energy systems and also low carbon policy objectives.

1 | INTRODUCTION

The drive towards a net-zero society by 2045 is a key target outlined by the Scottish Government in their energy transition strategy [1] where it is anticipated that the uptake of low carbon technologies (LCTs) such as solar PV, electric vehicles (EVs), heat pumps and energy storage, will support the transition towards a 100% renewable-energy system [2]. To facilitate this transition, interim targets have been established in a bid to ensure the necessary uptake of these LCTs. Prominent targets include: the equivalent of 50% of total energy demand across heat, transport and electricity to be met from renewable energy by 2030 [3], the need for new cars and vans with internal combustion engines to be 'phased out' by 2032 [4] and new residential buildings consented from 2024 to use renewable or low carbon heat [5]. These targets emphasise the scale of LCT uptake expected in the coming years and ultimately the scale of the electrification challenge. From an electrical distribution network perspective, the increase in demand and uncertainty associated with this uptake is of significant concern for distribution network operators (DNOs). These concerns are exacerbated when considering rural networks in Scotland which consist of sparsely located demand centres supplied by overhead lines (OHLs) that span challenging terrains and must endure adverse weather conditions. This is particularly challenging for areas not connected to the gas network where the use of hydrogen is impractical [6] and, due to limited public transport services, have an increased reliance on private vehicles for travelling.

As consumer reliance on the electricity network for heating and transport increases, security of supply concerns are amplified for DNOs. Conventionally, DNOs are required to maintain security of supply through asset management and network reinforcement, making decisions based on a limited measurement set [7, 8]. However, as distribution networks continue to evolve and as DNOs transition to distribution system operators, there is already a growing requirement for more flexible approaches to network management as opposed to the conventional 'fit and forget' reinforcement methodology [9–11]. The development of 'smart' technologies and an increasing ethos for a 'flexibility first' approach presents an opportunity to limit the need for network reinforcement [12]. This is echoed by Ofgem (the network regulator for Great Britain (GB)) where they have emphasised that DNOs should be exploiting flexible network management solutions across the next price control period (RIIO-ED2) [13].

With the demand for flexible network management solutions increasing, battery storage technology has attracted significant attention in recent years due to its low carbon flexibility potential [11]. Therefore, presenting as a potential candidate for displacing conventional backup carbon-intensive diesel generators that are still heavily relied on across the UK, particularly in rural Scotland, National Grid recently issued a call for innovation to businesses across the UK to find new low-carbon alternatives to backup diesel generators which reiterates the need for novel management solutions in this space [14]. However, in addition to the technological differences, a significant challenge with this displacement is the current cost of battery storage compared with backup diesel generators if displaced on a like for like basis, that is, solely used in a backup capacity. Consequently, to maximise cost-effectiveness and asset potential, there is a growing demand to utilise 'multi-functional' storage, that is, for a given primary function, strengthen the overall asset value and the business case for deployment by offering additional functionality, for example, flexibility as a service. This concept of 'multi-functional' storage has been considered in works such as [15] and [16] recognising that it can offer various benefits in support of cost-effective decarbonisation and more efficient asset utilisation. However, there remains a lack of understanding surrounding the interplay and relationship between different functionalities and their adequacy to reliably support network management and operation.

In parallel, there is a growing demand to maximise the renewable energy potential of the available generation capacity [8]. As described in [17] and [18], this in part can be achieved by coordinating flexible demand to coincide with periods of increased output from renewable generation, either autonomously or through manual intervention, for example, by encouraging more energy aware consumer behaviour in terms of appliance use. Existing works including [19] have used the electricity time of use price as a dispatch metric, whereas others including [20] have used multi-period optimal power flow with storage to minimise generation cost. However, the carbon intensity (CI) – which is a measure of how much carbon dioxide emissions are produced per kilowatt hour of electricity consumed – of the available generation mix presents as an alternative. From a consumer perspective, this metric has the potential to encourage 'smarter' energy use for those that are not entirely motivated by monetary value but by other factors such as carbon footprint. A practical example is 'The Green Light Signal' [21] which utilises a carbon intensity metric to signal 'smart' light bulbs, visually informing consumers of when it is most efficient to use their appliances. Also, a low carbon route planner function for EV drivers is proposed in [22] to allow drivers to optimise their travel arrangements according to the CI of their charging. In [23], the carbon intensity metric has been adopted and autonomously used to schedule EV charging, indicating that through carbon optimised scheduling a lower overall carbon footprint from a fleet of EVs can be achieved.

This motivates the authors to investigate, via modelling of a 'real' HV-LV distribution network developed from DNO geographic information system (GIS) data, the challenges and opportunities presented by battery storage and how it can be preferentially dispatched under constraint conditions to displace the use of backup diesel generators and reduce curtailment of renewable generation. To understand the challenges and opportunities associated with multi-functional battery storage and the interplay between different operational functionalities, carbon control, guided by [22], is then introduced as a secondary function of the storage with dispatch control based on CI data for GB made available by the electricity system operator; NGESO (National Grid Electricity System Operator) [23]. In the management of rural networks, this multi-functional control strategy has the potential to facilitate decarbonisation through the displacement of carbon-intensive diesel generators whilst supporting local low carbon network balancing in the drive towards 'carbon neutral' and self-reliant networks. Facilitating a reduction in the local carbon footprint, the distribution losses and deferring extensive network reinforcement. As such, the primary contributions of this paper are summarised as follows:

- The work investigates the challenges of displacing co-located backup diesel generators with battery storage in the context of constraint management. The assessment is carried out on a 'real' HV-LV model and provides valuable insight into the issues with decarbonisation of last resort carbon-intensive technologies.
- The work builds on this assessment and develops a multi-functional battery control strategy that integrates constraint management and carbon control. This functionality supports cost-effective decarbonisation and low carbon network balancing in the drive towards self-sustaining carbon-neutral local distribution networks.
- Through the development of this strategy, the work then explores the inherent challenges with multi-functional battery storage and the uncertainty surrounding the interplay between the modelled functionalities and as the combination of these functions has had minimal exposure within the existing literature the investigation is considered to be state-of-the-art.

The remainder of the paper is structured as follows. Section 2 describes the model development and includes an overview of the underlying models, the approach taken to model demand and generation and a summary of the battery storage control approach. Section 3 describes the studies undertaken where two scenarios are considered, with both containing several sub-cases, and their associated findings. Section 4 provides a discussion of the findings. Section 5 concludes the analysis and describes future work opportunities.

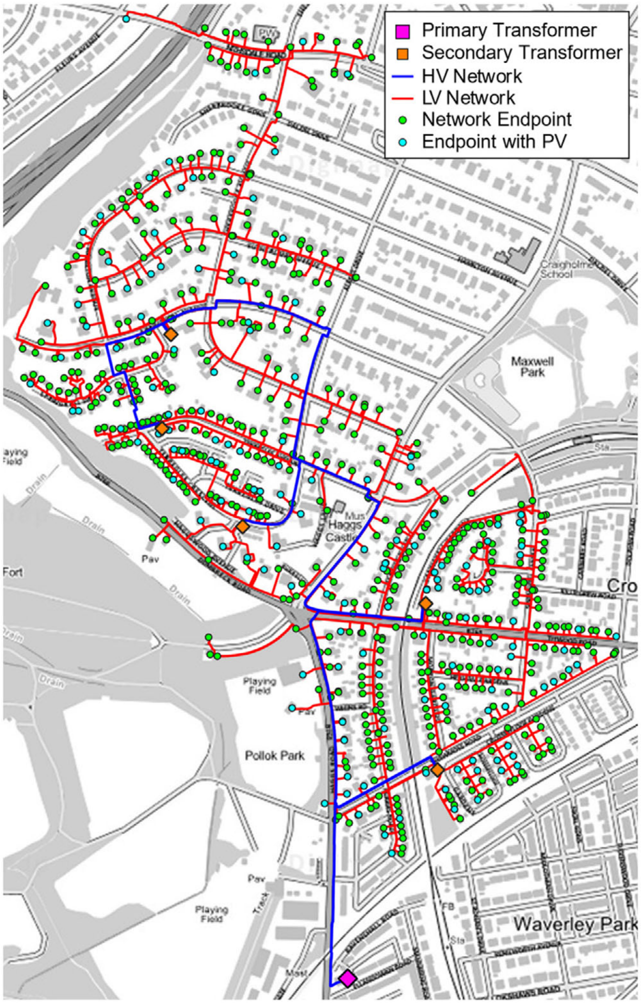

FIGURE 1 Network GIS data overlaid on map of supplied area

2 | MODEL DEVELOPMENT

This section outlines the development of the network model and the generation and demand profiles. It also describes the approach taken to model the battery and carbon intensity control.

2.1 | Distribution network

The area selected for analysis was extracted from Scottish Power Energy Network's (the DNO for south and central Scotland) GIS data and is presented in Figure 1 [24, 25]. The network contains 857 network loads with a fixed power factor of 0.95 applied to each based on [26]. The network has been assumed balanced in absence of detailed information relating to individual phase connections. A fixed penetration of solar PV has been stochastically distributed throughout the network.

The HV (11 kV) and LV (400 V) networks are supplied via an OHL connected to a grid supply which is modelled as a slack bus. A singular OHL is representative of how many rural communities in Scotland are supplied and was sized based on after diversity maximum demand (ADMD) [27] and then marginally oversized as is often the case in practice. This has been generalised in this paper based on typical approaches to network planning and asset sizing but these can differ between DNOs who may have different network planning practices. To facilitate local network balancing, and for modelling simplicity, generation assets are connected to the 11 kV primary transformer bus. This includes a 1000 kVA hydro scheme connected via an OHL and a 250 kVA diesel generator. These assets have been added to the network model as it is not uncommon throughout rural Scotland due to geographic and climate conditions for backup diesel generators to be co-located with hydro generation.

Battery storage is also connected to this bus to mitigate the impact of asset connection location within the analysis. A 1000 kWh battery with unity power factor and a continuous import/export rating of 250 kW is used. Fixed battery losses are considered in the modelling at 1% of the real power rating together with a charge and discharge efficiency of 98% [28]. In the studies presented, the storage has been sized to align with the backup diesel generator rating. Note that this work is not focused on optimal sizing of storage but rather to emphasise the challenges for using storage in a backup capacity during periods of outage or constraint in addition to service provision.

2.2 | Demand and generation profiles

The CREST demand model [29] is used to generate diversified demand profiles for the 857 network loads at a 5-min resolution based on domestic household occupancy and behaviour. The model is based on the UK Time Use Survey (TUS) [30] which is a large-scale survey that documents consumer household behaviour and has been widely used in literature [24, 31]. The model requires several inputs including: month, day (weekend or weekday), number of residents (1–4+) and household type (semi-detached, detached or terraced) to generate the unique individual demand profiles for each household. In [24], the housing stock for the network and the probability of residents per household is obtained from a UK Ordnance survey building type dataset and GIS data of the 2011 UK Census Output Areas (OAs). The number of occupants per household attached to the highest probability is used to allow for the most likely loading scenario to be studied.

The CREST model is also used to generate unique individual solar PV profiles. These are generated independently of the individual household demand profiles ensuring that the net aggregate of both demand and distributed generation is calculated separately. The model stochastically generates the representative solar PV profiles by considering cloud coverage and sun irradiance. For a 20% solar PV distribution (171 households), a distribution of 66, 56 and 49 is considered for the three different array sizes available within the model (7 m^2, 10 m^2, 13 m^2). Each PV system is modelled to have a unity power factor and it is assumed, due to the close geographic nature of the network loads, that households with PV share the same irradiance profile. Although output from hydro generation can vary based on rainfall and other climatic factors, for this study minimal variance has been assumed over an individual day.

2.3 | Carbon intensity modelling

The CI is a measure of how much carbon dioxide emissions are produced per kilowatt hour of electricity consumed from the available generation mix and is calculated by NGESO at half hourly time intervals using the following:

$$C_t = \frac{\sum_{g=1}^{G} P_{g,t} \times C_g}{D_t}, \tag{1}$$

where C_t is the carbon intensity at time t, C_g is the carbon intensity of fuel type g and $P_{g,t}$ is the generation of that fuel type. D_t is the total national demand for GB at t. The accuracy of this calculation is highly dependent on the representation of the output from the available generation mix, the true system demand, and the individual fuel type carbon intensity values which are documented in [32]. In managing the balancing mechanism, NGESO have access to historic generation and demand data that has allowed for the development of a CI forecasting methodology also described in [32]. CI forecasting can therefore be incorporated into future modelling to provide insight on future dispatch conditions. However, for this work, historic values are used to demonstrate the control process.

As a secondary function of the battery storage, CI is used to drive battery charge and discharge actions with the intention of limiting interaction with the grid to periods of increased renewable generation supporting a local low carbon benefit. In GB although smart meter data is also recorded at a half hourly time interval, concerns have been raised as to the applicability for dynamic control at this resolution [7]. Therefore, it has been assumed that the CI remains constant throughout each half hourly time step allowing for control at a 5 minutely resolution which aligns with the CREST demand model. The CI figures used in this work are obtained from a callable Python script to NGESO's CI Application Programming Interface (API) [33]. The carbon control constraints are modelled based on the boundaries defined by NGESO in [32], where the CI condition is classified based on the measured carbon intensity (ci) in gCO2/kWh at a given time. This is expressed as

$$CI = \begin{cases} \textit{Very High}, & ci \geq 360 \\ \textit{High}, & 360 > ci \geq 260 \\ \textit{Moderate}, & 260 > ci \geq 160 \\ \textit{Low}, & 160 > ci \geq 60 \\ \textit{Very Low}, & 60 > ci \end{cases}. \tag{2}$$

The battery dispatch actions linked to these constraint conditions are defined in each of the relevant studies as outlined in Section 3.

2.4 | Multi-functional control methodology

A control methodology was developed to accommodate both the constraint management (CM) and the carbon control (CC). A simplified version of this is shown in Figure 2. The flow direction can dictate which equations and constraints are utilised for a given instance. In the proceeding equations, standard logical operators $\wedge$ for AND and $\vee$ for OR are used when equations or constraints are subject to variations in flow direction in Figure 2. To determine the required functionality, the power flow imbalance is determined by first calculating the aggregated power of local generation and demand at time $t = \Delta t$ as follows:

$$P_{\text{dem}} = \sum_{i=1}^{n} lp_i \wedge P_{\text{gen}} = \sum_{j=1}^{m} gp_j \tag{3}$$

where P_{dem} represents the aggregated demand at the 11 kV side of the primary transformer, lp_i is the measurement of the ith consumer load profile at the tth interval, and n is the number of connected loads. The term P_{gen} is calculated using the same approach by considering all connected generation, where gp_j is the measurement of the jth generation profile at the tth interval, and m is the number of connected generating units.

The power flow direction indicates the state of imbalance, that is, by determining if the local network is balanced, importing or exporting, this is expressed as

$$P_{\text{PF}} = P_{\text{dem}} - P_{\text{gen}} + P_{\text{losses}}, \tag{4}$$

where P_{losses} relates to local network losses and P_{PF} represents the active power flowing through the primary transformer. From this, the constraint conditions for each functionality are defined. For constraint management, (5) and (6) indicate when the local network is either importing or exporting.

$$P_{PF} > x, \tag{5}$$

$$x > P_{PF}, \tag{6}$$

where x is the line capacity (negative when exporting, positive when importing). This is either a constrained capacity or maximum capacity. When no line constraints are observed, the carbon control is used where (7) and (8) determine if the local network is importing or exporting.

$$x \geq P_{PF} > 0, \tag{7}$$

$$x \leq P_{PF} < 0. \tag{8}$$

The network is balanced when

$$P_{PF} = 0, \tag{9}$$

where in this instance no control actions are taken.

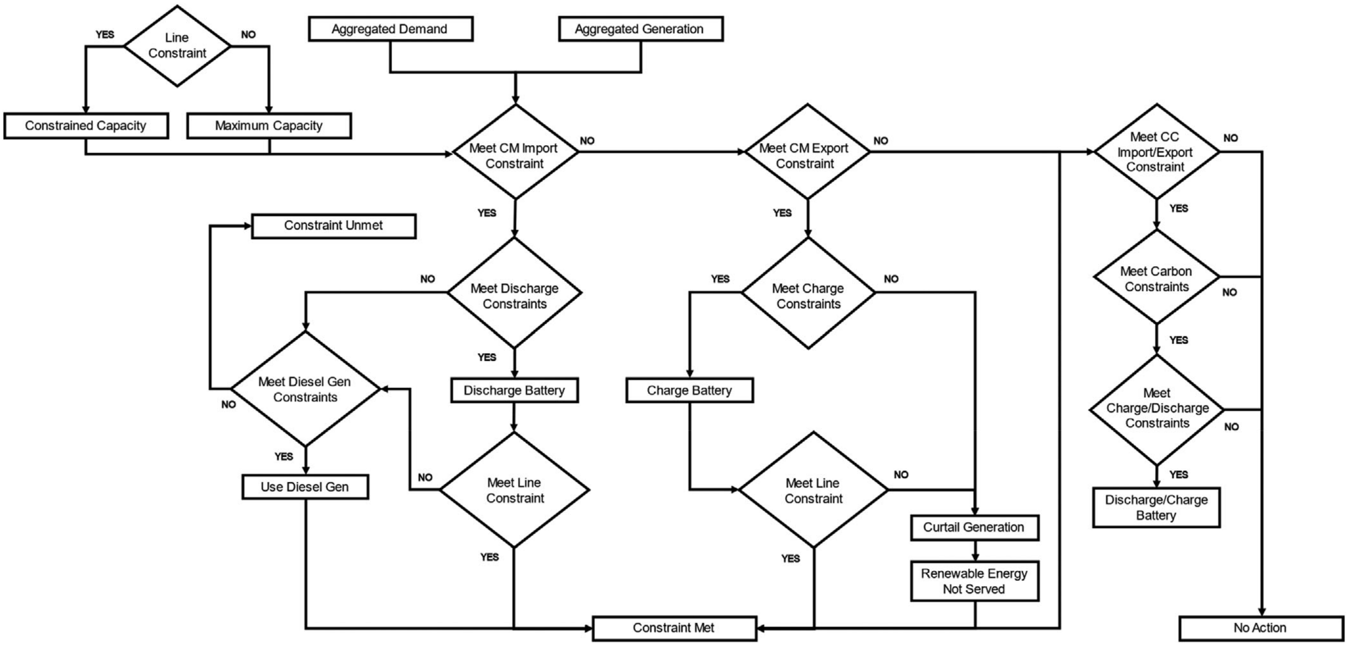

FIGURE 2 High-level overview of the multi-functional control methodology

2.4.1 | Battery energy storage model

A battery controller has been developed to manage the charging and discharging of the battery, and to account for variation in battery state-of-charge (SOC). The battery's primary function is to support constraint management by operating in a backup capacity, displacing conventional diesel generation, and reducing curtailment of renewable sources, as necessary. The secondary function is to perform CI-driven dispatch in support of low carbon network balancing. When neither charging nor discharging, the battery remains in idling mode. The battery used in this work is of the lithium-ion type, and it is therefore typical that the battery is not fully discharged with a margin of capacity held to ensure battery longevity. Subsequently, the minimum energy capacity $E_{\min}$ is set at 200 kWh (20% SOC). The maximum energy capacity $E_{\max}$ equates to the rated energy capacity of the battery (100% SOC) in this case 1000 kWh. The charge and discharge constraints for the battery are defined as follows:

$$(E_{\max} > E_{\mathrm{t}} \geq E_{\min}) \vee (E_{\max} \geq E_{\mathrm{t}} > E_{\min}), \tag{10}$$

$$P_{\max} \geq P_x, \tag{11}$$

$$E_x \geq E_{\mathrm{avl}}, \tag{12}$$

where E_{t} is the energy held within the battery at a given time-interval $t = \Delta t$ and $P_{\max}$ is the maximum charging power. For CM, P_x is the excess active power exceeding the constraint and for CC it is the active power allowed with respect to the line capacity. E_x is the energy equivalent of P_x, P_{avl} is the available charging power and E_{avl} is the energy equivalent. The charging and discharging power P_{ch} and P_{dch} are determined according to

$$P_{\mathrm{ch}} \vee P_{\mathrm{dch}} = \begin{cases} 0 \\ P_x \\ P_{\mathrm{avl}} \\ P_{\max} \end{cases}, \text{ subject to } (5) - (12), \tag{13}$$

where E_{avl}, P_{avl} and P_x are calculated as follows:

$$E_{\mathrm{avl}} = (E_{\max} - E_{\mathrm{t}}) \vee (E_{\mathrm{t}} - E_{\min}), \tag{14}$$

$$P_{\mathrm{avl}} = \frac{E_{\mathrm{avl}}}{\Delta t}, \tag{15}$$

$$P_x = (x - P_{\mathrm{PF}}) \vee (P_{\mathrm{PF}} - x). \tag{16}$$

A minimum charge of 1.2% of the kW rating (i.e. 3 kW) is required to overcome fixed losses. Essentially this sets an upper bound tolerance where idling mode is forced. This also ensures a positive change in energy when the battery is in charging mode. The change in energy is expressed as follows:

$$\%\Delta SOC = \left(\frac{(\eta E_{\mathrm{ch}}) \vee \left(\frac{1}{\eta} E_{\mathrm{dch}} \right)}{E_{\max}} \right) \times 100, \tag{17}$$

where E_{ch} is the energy charge increase, E_{dch} the decrease and $\%\Delta SOC$ the SOC percentage change between time intervals.

There is no end of day constraint for the battery and the SOC is retained at the end of each day. This allows for a more active capacity which is valuable for analysis across multiple days and would be the subject of future work.

2.4.2 | Diesel generator

The diesel generator is only used as necessary for constraint management and is subject to either of the following constraints:

$$\left(P_{\mathrm{d}}^{\max} \geq P_{x}\right) \vee \left(P_{\mathrm{d}}^{\max} \geq P_{\mathrm{dch}}^{\mathrm{x}}\right), \tag{18}$$

where $P_{\mathrm{d}}^{\max}$ is the rated output of the diesel generator and P_{dch}^{x} is the excess power remaining should battery discharge fail to meet the line constraint (see Figure 2) as calculated by

$$P_{\mathrm{dch}}^{\mathrm{x}} = P_{\mathrm{x}} - P_{\mathrm{dch}}. \tag{19}$$

The output from the diesel P_{d} is determined according to

$$P_d = \begin{cases} 0 \\ P_x \\ P_{dch}^{x} \\ P_d^{\max} \end{cases}, \text{ subject to } (5) - (13) \wedge (18). \tag{20}$$

2.4.3 | Curtailment approach

The curtailment approach is only used for constraint management and any action that is required is applied to the output of the hydro generator and solar PV as appropriate. Disaggregated curtailment of residential solar PV is typically uncommon in current GB network practice and is predominantly only utilised within a microgrid environment due to the communications and control infrastructure necessary. However, until sufficient flexibility is available through distributed assets this may prove necessary as penetrations increase. Therefore, curtailment is simply modelled here on a pro-rata basis given the volume of the installations. This is conditional on whether the battery is charging or not, therefore, the aggregate generation required for network balancing that is, the aggregated generation after curtailment ($P_{\mathrm{gen}}^{\mathrm{cur}}$) is based on

$$P_{\mathrm{gen}}^{\mathrm{cur}} = \left(P_{\mathrm{gen}} - \left(x - P_{\mathrm{PF}}\right)\right) \vee \left(P_{\mathrm{gen}} - \left(x - P_{\mathrm{PF}} + P_{\mathrm{ch}}\right)\right). \tag{21}$$

The percentage contribution for each generating unit $j = 1, 2, 3, \ldots, m$ in relation to P_{gen} is then calculated and applied to the curtailed aggregate to determine the reduced contribution per generating unit as follows:

$$P_{\mathrm{gen},j}^{\mathrm{per}} = \frac{gp_j}{P_{\mathrm{gen}}}, \tag{22}$$

$$g\mathrm{p}_j^{\mathrm{cur}} = P_{\mathrm{gen}}^{\mathrm{cur}} \times P_{\mathrm{gen},j}^{\mathrm{per}}. \tag{23}$$

This approach allows for curtailment of generation for all possible conditions.

3 | LOCAL NETWORK OPERATIONAL SCENARIOS

This section describes a series of different case study scenarios that are used to demonstrate the developed modelling approach under different network constraint conditions.

3.1 | Scenario 1: Importing

This scenario focuses on occasions when the local network acts as an 'importer'. To facilitate this, the hydro plant is assumed to be disconnected, this could be due to plant failure, OHL outage or due to general maintenance. This operating condition essentially applies to most current networks, particularly, where there is limited penetration of DG or flexible LCTs. For each case, four constraint scenarios are considered on a mid-week winters day in February, where the capacity of the grid supply is constrained to: 80%, 70%, 60% and 50% of the OHL capacity between the time period of 18:30 and 21:30 (this represents a worst-case scenario). The size of these constraints is considered to be infrequent from a day-to-day network operational perspective, though have been selected to demonstrate the potential scale of the impact faced.

The carbon control for when the local network is importing is configured to discharge when the CI condition is Very High or High and charge when the CI is Moderate, Low or Very Low. The daily CI profiles are taken from historical records from the winter of February 2020 to demonstrate the methodology and operational intricacies [33].

Each case demonstrates a different operational scenario where the case specifics and findings are recorded as follows:

Case 1: This case will represent the base study where backup diesel generation is used to meet demand in the event of a constraint. This could be considered conventional network operation and is shown in Figure 3. The figure emphasises that as the grid supply capacity reduces, reliance on the diesel generator increases. The 'Demand Unmet' is a consequence of the grid operating as a slack bus, indicating that for the modelled reduced capacity period, the demand could not be met under the constraint conditions despite the diesel generation operating at rated output. In practice, this scenario would cause the associated protection to trip and disconnect consumers. As these constraints are considered atypical or 'extreme', this scenario would be highly uncommon under day-to-day operation. Additionally, it would be feasible to consider that network planners would have historically sized any backup diesel generation to secure against constraints by considering the risk, probability and severity of such events, therefore ensuring sufficient backup capacity for the majority of probable events, ensuring a trade-off between resilience and cost. However, they may have also sized the diesel generation to secure against the largest anticipated event based on a network assessment of the surrounding infrastructure and therefore such a scenario may never occur.

As the constraint event occurs during the evening demand peak in winter, which is representative of the worst-case scenario, the distributed solar PV fails to contribute during the constraint period. However, during the day when sunlight would be more prominent, supply from the grid is reduced and therefore as penetrations increase, reliance on the grid would continue to decrease, increasing local network self-sufficiency (Figure 3).

Case 2: The battery storage is introduced to displace the conventional backup diesel generation. For simplicity, in this case, at the beginning of day the battery SOC is taken to be 100%. In practice, depending on storage functionality, that is, if to make the storage more economically viable, other services are utilised in addition to its backup primary function, the SOC at the beginning of the constraint period would vary as explored in the proceeding cases. The displacement of diesel generation by introduction of battery storage is shown in Figure 4. The figure indicates that for each constraint scenario the demand is sufficiently met under constraint conditions. However, as the severity of the constraint increases reliance on the diesel generation is still necessary, although the output is significantly reduced. This is fundamentally a consequence of storage sizing which emphasises the importance for full displacement. To fully displace conventional backup diesel generators with battery storage the increase in demand associated with LCTs must be considered in the sizing process. However, with increasing penetrations of such technologies, there is an opportunity to utilise the inherent flexibilities through 'smart' control to assist the backup storage and this too must be considered.

Case 3: For this case, the carbon control is introduced in addition to the constraint scenario. The CI of the grid supply drives the charge and discharge actions of the storage, and the constraint scenarios are maintained to determine if sufficient capacity is available to meet the demand under the varying conditions. This is demonstrated in Figure 5 which highlights the carbon control in conjunction with constraint management for a winter's day in February 2020. This dispatch is based on the CI and initially when the CI is Moderate the storage is at full capacity, therefore is not charging. However, as the CI increases to High the storage is discharged, reducing the supply of carbon intensive power from the grid. The storage then switches to charging mode as the CI reduces to Moderate. A visible increase in the grid

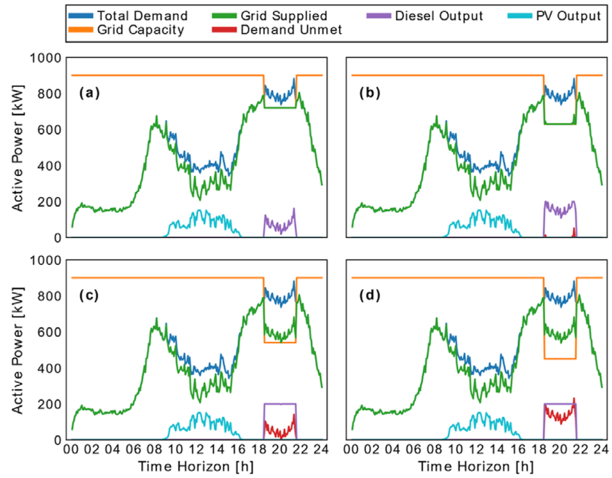

FIGURE 3 Importing Case 1: backup diesel operation without BESS for reduced OHL capacities of (a) 80% (b) 70% (c) 60% and (d) 50%

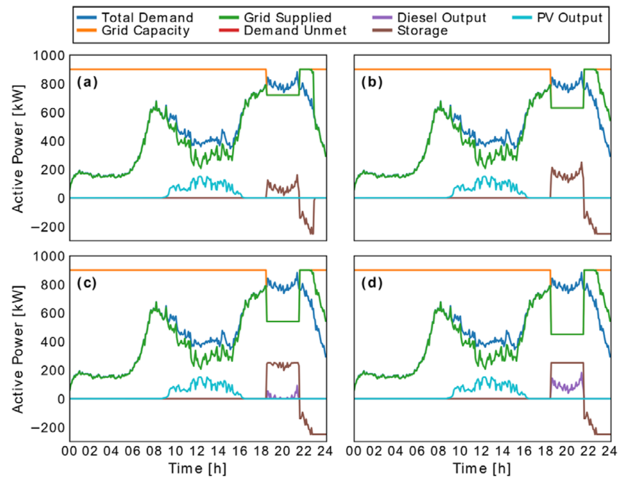

FIGURE 4 Importing Case 2: introduction of BESS to displace backup diesel operating under reduced OHL capacities of (a) 80% (b) 70% (c) 60% and (d) 50%

supply is observed and as the storage reaches its full capacity, it returns to idling mode. It is then fully discharged to the minimum threshold of 20% SOC as the CI is High for a prolonged period in the afternoon to early evening. When discharging, the supply from the grid is reduced close to zero. Crucially, as the storage capacity is at its minimum threshold when the constraint occurs, the storage is incapable of contributing to meet the demand. Reliance on the diesel is still prevalent which raises concerns with the ability of storage to be solely carbon controlled and fulfil its primary backup function with the current capacity limits.

Case 4: This case considers both carbon control and the previous constraint scenario. However, an additional constraint for the period between 07:00 and 10:00 is introduced. This provides insight into the use of carbon control with respect to multiple constraints. This case is highlighted in Figure 6 where the morning constraint

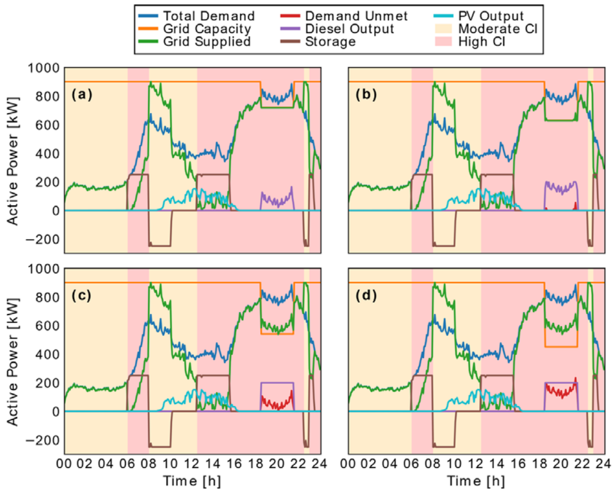

FIGURE 5 Importing Case 3: carbon control and constraint management for reduced OHL capacities of (a) 80% (b) 70% (c) 60% and (d) 50%

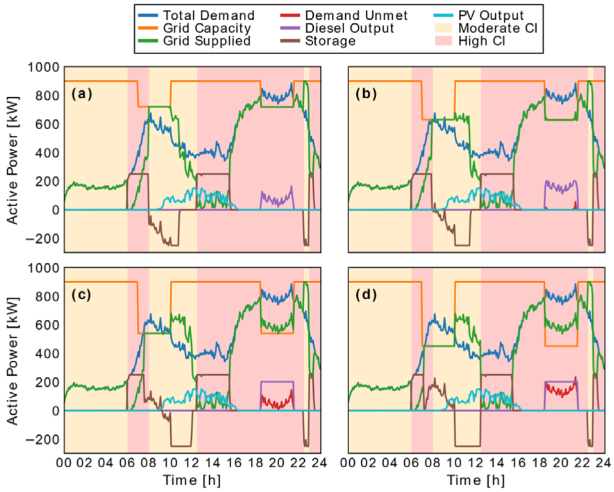

FIGURE 6 Importing Case 4: carbon control and constraint management for multiple constraints for reduced OHL capacities of (a) 80% (b) 70% (c) 60% and (d) 50%

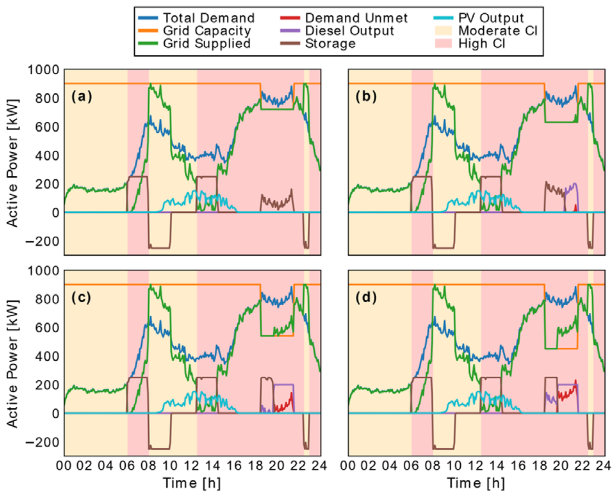

FIGURE 7 Importing Case 5: carbon control and constraint management with varying minimum capacity thresholds for reduced OHL capacities of (a) 80% (b) 70% (c) 60% and (d) 50%

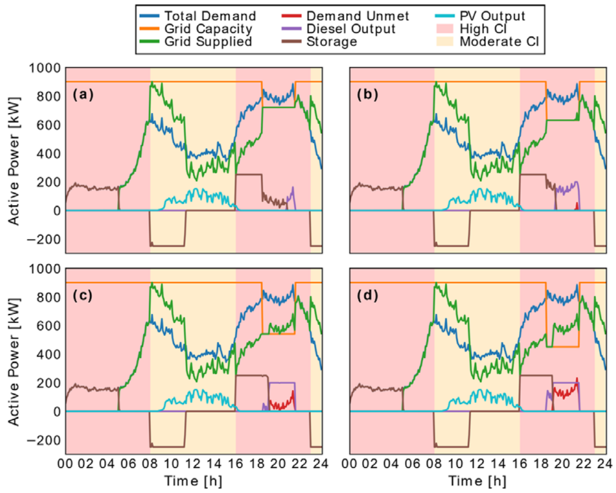

FIGURE 8 Importing Case 6: carbon control and constraint management with different CI profile for reduced OHL capacities of (a) 80% (b) 70% (c) 60% and (d) 50%

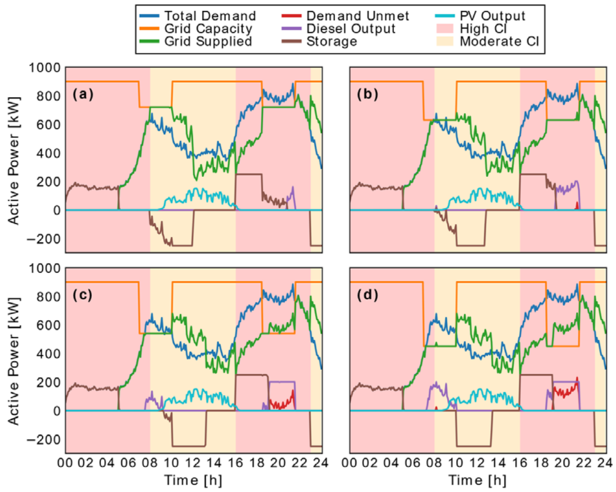

FIGURE 9 Importing Case 7: carbon control and constraint management for multiple constraints with different CI profile for reduced OHL capacities of (a) 80% (b) 70% (c) 60% and (d) 50%

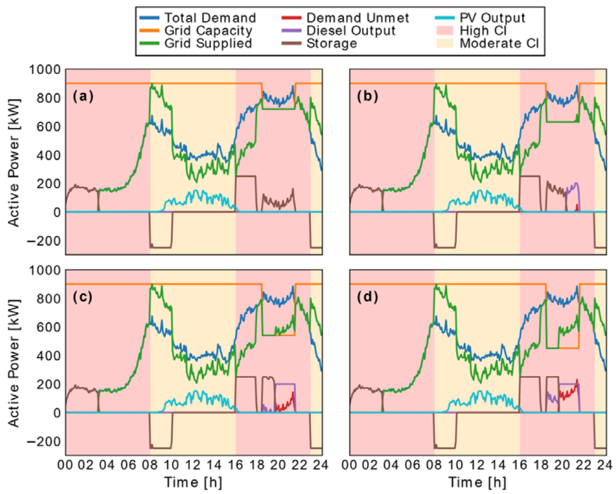

FIGURE 10 Importing Case 8: carbon control and constraint management with varying minimum capacity thresholds for different CI profile for reduced OHL capacities of (a) 80% (b) 70% (c) 60% and (d) 50%

is fully met in each scenario. However, the evening remains unmet by storage. Figure 6(a) and (b) emphasises that the morning constraint is sufficiently low to allow the storage to charge during the initial period of Moderate CI, though as the constraint severity increases in (c) and (d) the storage has to discharge to meet the demand.

Case 5: In this case, the minimum SOC threshold is adjusted to ensure a level of capacity is available for backup functionality. This case considers the minimum SOC threshold for carbon control to be 50% and 20% for constraint conditions. This allows for 50% of the capacity to be used for network services, for example, local balancing via carbon control whilst maintaining a level of capacity for backup to be utilised in the event of a network constraint. This is demonstrated in Figure 7 where the storage contributes more and reduces reliance on the diesel generator as compared with Figure 5. To ensure optimal use of the battery capacity, the capacity held in reserve for backup would likely be based on the magnitude, frequency and constraint length of the most probable constraints for a given network.

Case 6, 7 and 8: These cases repeat cases 3, 4 and 5 with a different CI daily profile to emphasise the change in control behaviour and results are presented in Figures 8–10. Figure 8 indicates that due to the change in the daily CI profile, storage has more of a contribution to constraint management in the evening as compared with Figure 5. However, in Figure 9 the morning constraint requires reliance on the diesel unlike in Figure 6.

In summary, the results presented in this section provide insight into the potential of and challenges with utilising multi-functional battery storage for low carbon local network balancing and constraint management when importing. The uncertainty surrounding when constraints are likely to occur, and their severity, challenges the ability to ensure sufficient adequacy whilst providing local balancing services driven by the grid's CI. However, as demonstrated in Case 4, by managing the capacity constraints, this can prove to be an effective measure in ensuring sufficient capacity if appropriately sized (noting that the authors consider the constraint scenarios to be 'extreme'). A disadvantage with this approach is that a portion of the battery's capacity would remain unutilised for the majority of the asset's lifespan.

However, there are existing ancillary service markets such as 'black-start' provision that pay generators to hold reserve [34]. Forecasting techniques and risk monitoring could be incorporated to manage this reserve capacity for more optimal use of the capacity.

3.2 | Scenario 2: Exporting

This scenario focuses on occasions when the local network acts as an 'exporter', such that the output from local generation is larger than that of the demand and the excess generation is fed back to the grid. To model this condition, the hydro generating plant is re-connected. Similar to scenario 1, this scenario considers the same number of cases with equal constraint scenarios per case. However, in this scenario the constraint period is shifted to 02:00–05:00 to account for a period of low demand which is considered the worst-case scenario for a weekday in July. For the carbon control in this scenario the storage is charged when the CI is classified as Very Low or Low and discharged when Moderate, High or Very High.

Case 1: This is the base case for this scenario where there is an excess of local generation and curtailment is necessary to meet a constrained export capacity. This could be considered conventional operation and is shown in Figure 11. The figure emphasises that as the available export capacity is reduced, curtailment of the hydro generating plant increases. Figure 11(c) and (d) emphasises

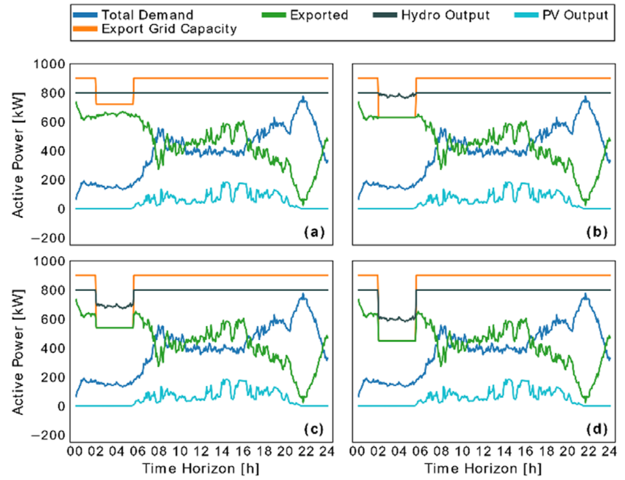

FIGURE 11 Exporting Case 1: generation curtailment without BESS for reduced OHL capacities of (a) 80% (b) 70% (c) 60% and (d) 50%

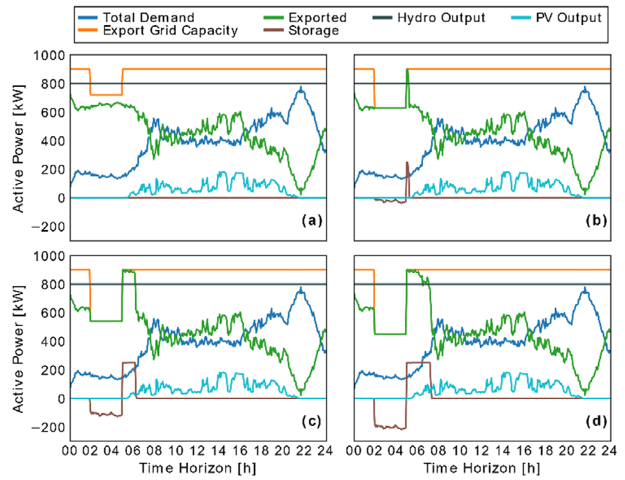

FIGURE 12 Exporting Case 2: introduction of BESS to reduce curtailment operating under reduced OHL capacities of (a) 80% (b) 70% (c) 60% and (d) 50%

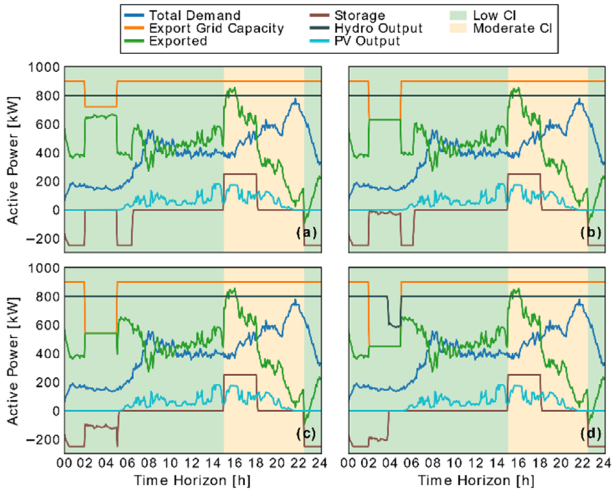

FIGURE 13 Exporting Case 3: carbon control and constraint management for reduced OHL capacities of (a) 80% (b) 70% (c) 60% and (d) 50%

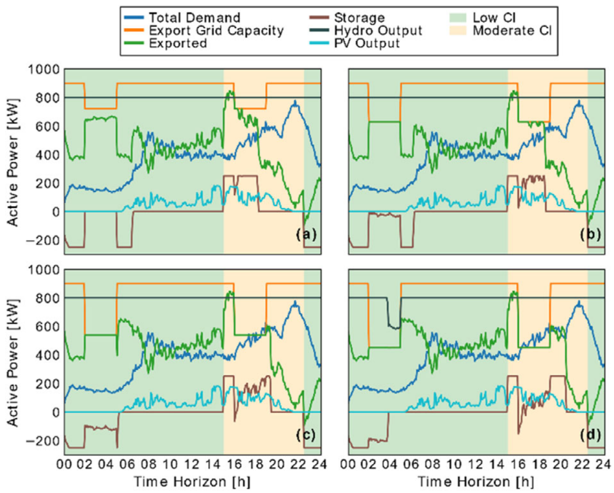

FIGURE 14 Exporting Case 4: carbon control and constraint management for multiple constraints for reduced OHL capacities of (a) 80% (b) 70% (c) 60% and (d) 50%

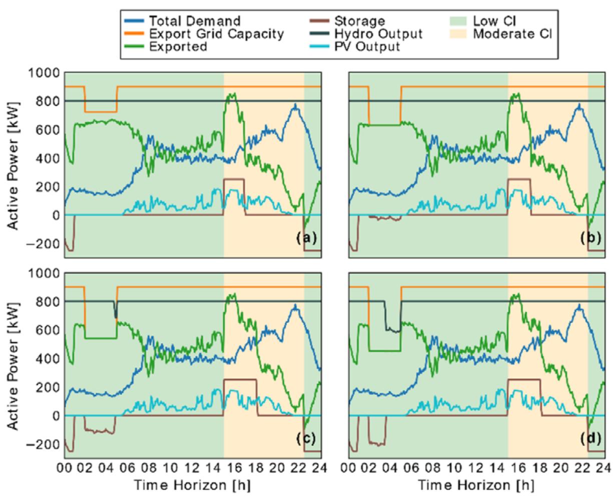

FIGURE 15 Exporting Case 5: carbon control and constraint management with varying minimum capacity thresholds for reduced OHL capacities of (a) 80% (b) 70% (c) 60% and (d) 50%

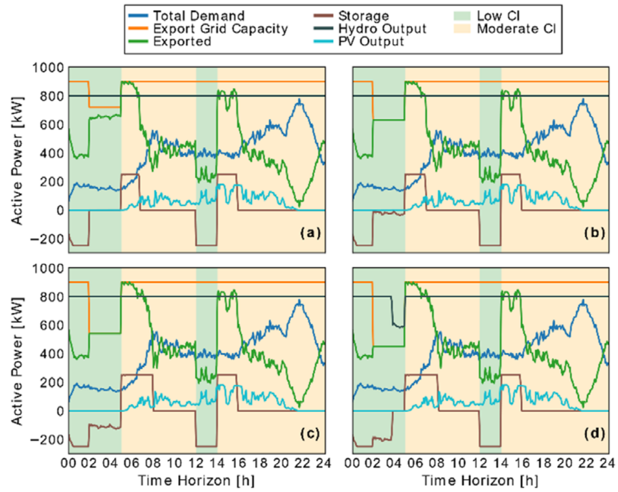

FIGURE 16 Exporting Case 6: carbon control and constraint management with different CI profile for reduced OHL capacities of (a) 80% (b) 70% (c) 60% and (d) 50%

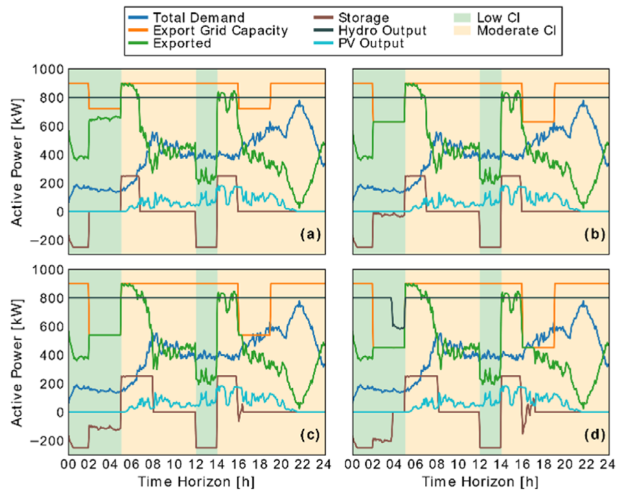

FIGURE 17 Exporting Case 7: carbon control and constraint management for multiple constraints with different CI profile for reduced OHL capacities of (a) 80% (b) 70% (c) 60% and (d) 50%

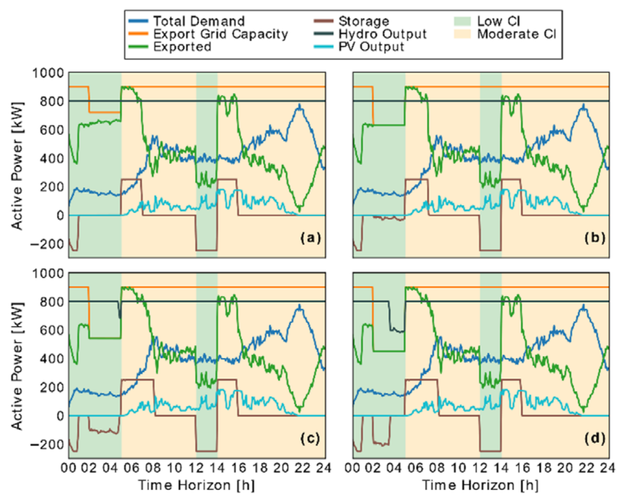

FIGURE 18 Exporting Case 8: carbon control and constraint management with varying minimum capacity thresholds for different CI profile for reduced OHL capacities of (a) 80% (b) 70% (c) 60% and (d) 50%

that due to contribution from PV between 12:00 and 18:00, should a constraint of this magnitude occur during this period, there would be a need to curtail residential PV. Due to the limited visibility of existing DG and the level of control and communication infrastructure necessary, this is not typical practice for DNOs in GB. This level of control is more common when operating microgrids. However, this raises concerns for only 20% penetration of PV, and as penetrations continue to increase alongside the growth of other LCTs, curtailment may become necessary under less severe (more probable) constraints in absence of flexible alternatives.

Case 2: In this case, the battery storage is introduced with the intention of reducing the need to curtail local generation under an export constraint. The SOC is assumed to be fixed at 20% before the constraint event. This is demonstrated in Figure 12 where the need to curtail the hydro generation is reduced as the storage is charged. Note that when the storage is negative, this indicates the battery is in a charging condition. By charging the storage with excess generation, it reduces the total energy not served by the hydro plant and would allow the plant owners to continue to profit from the output, this is crucial as curtailment assessments can be highly influential to the business case for local DG installations [8]. By reducing curtailment requirements, the renewable energy potential is maximised, and DG owners can be encouraged to connect their plant into previously constrained areas of network. The storage is discharged here as the maximum available export to the grid is prioritised to support demand in close proximity to the local network.

Case 3: The carbon control is introduced alongside constraint management in this case and is presented in Figure 13. The figure highlights that when the CI is Low, the storage charges and the amount exported to the grid is reduced. As the constraint occurs, the storage is charged as necessary to ensure the maximum available export to the grid is achieved. Equally the battery charging could be prioritised over export to the grid. However, if the storage is prioritised, depending on constraint length, it could become fully charged during the duration of the constraint and therefore curtailment would be necessary. Prioritisation would vary between the different actors involved, for example, the DNO, storage owner and the local community which introduces an additional level of complexity. However, fundamentally the DNO is the party responsible for ensuring security of supply.

Case 4: This case demonstrates the carbon control and constraint management for multiple constraints. The results associated with this case are presented in Figure 14. Figure 14(c) and (d) shows the storage fluctuates between charging and discharging to ensure the export constraint is sufficiently met and that maximum low carbon generation is exported to the grid during periods when the grid CI is considered Moderate.

Case 5: This case considers the impact of adjusting the charge thresholds for the differing functions. However, due to the constraint time, the SOC is assumed to be fixed at 50% before the constraint event and not 20% like in previous cases. This is demonstrated in Figure 15 where the difference of this is clear when directly compared to Figure 13. In Figure 15, the storage is fully charged to the upper threshold for the carbon control functionality, which in this case is set at 70%, leaving 30% capacity as reserve for constraint management. In Figure 15(c) and (d), additional curtailment is required due to the storage starting at 50%, fully charging to the 70% threshold, then highlighting that the remaining capacity is not sufficient to meet the constraint. This reinforces the importance of sizing the capacity thresholds relatively to the anticipated constraints.

Case 6, 7 and 8: As with the import scenario, these cases repeat cases 3, 4 and 5 with a different CI daily profile to emphasise the change in control behaviour and results are presented in Figures 16, 17 and 18.

In summary, this section explores the challenges associated with the multi-functional approach that includes constraint management and carbon control for an exporting local network. Storage proves to be suitable for reducing the level of curtailment necessary and the overall renewable energy not served. However, similar multi-functional operational challenges which involve carbon-driven control are emphasised as with the importing scenario. These include management of capacity constraints and the active nature of the SOC in relation to when constraint events occur.

4 | DISCUSSION

The results presented in this work identify practical challenges with the displacement of co-located backup diesel generation and reduction of generation curtailment using battery storage technology. The findings emphasise the importance of asset capacity constraints, particularly when securing against constraints of varying severity. These capacity restrictions are highly influential in terms of the battery's ability to manage unpredictable network constraints and have a greater impact on its effectiveness as a multi-functional asset. To fully displace these carbon-intensive assets, the frequency, magnitude and length of constraints commonly experienced on specific networks must be quantified, in addition to the anticipated growth of demand and LCT uptake. This would require additional operational data to be made available and a probabilistic assessment of the network and surrounding infrastructure alongside a cost-benefit analysis that considers the long-term financial benefit and the associated risk to network planning. However, if appropriately sized, the results indicate that battery storage can effectively support the displacement of backup diesel generators and with appropriate control, provide a reduction in local generation curtailment, the primary souce of 'green' electricity in rural enviroments.

A significant challenge with this evolution in isolation is the cost of battery storage compared with diesel generators and for optimal deployment in a continuously evolving network environment. Consequently, there is scope to strengthen the overall asset value and the business case for storage deployment by offering additional functionalities including flexibility as a service, for example, peak forecasted demand shaving and frequency response (an established GB market segment). Multi-functional battery storage with carbon control as a secondary function is considered to drive charge and discharge actions, essentially supporting low carbon network balancing which is a step towards facilitating not only 'carbon neutral' (and potentially carbon-negative) but also self-reliant or 'grid neutral' rural networks.

The results provide early insight into the challenges of managing smaller scale, decentralised energy systems that utilise smart technologies at the local level. Here battery storage with multi-functional uses that include last resort backup measures to secure against unplanned network constraints, and carbon control actions driven by a CI metric for local low carbon network balancing are specifically considered as an alternative management solution. The findings further emphasise the importance of asset capacity, but also the potential for management of individual functionality capacity constraints. They also indicate that by introducing additional functionality, the ability of the storage to fulfil its primary grid support function is challenged and subject to individual functionality constraint conditions. However, in this instance, with better foresight of probable constraints, multi-functional storage has the potential to be operationally and financially valuable. The ability of distributed flexible assets to support local carbon control is also highlighted and the role of these resources in providing flexibility must also be considered when using storage for constraint management. The dynamic control presented in this work falls broadly into the category of active network management (ANM) which requires an enhanced level of network visibility and communications and is largely unutilised in current distribution networks.

An additional consideration with multi-functional storage and the application of carbon control balancing is the increased number of charge and discharge cycles which will subsequently have an impact on the overall lifespan of the asset. Ownership of the storage, land and connection costs, regulatory/legal permits, the communications infrastructure and the interplay between relevant parties will play a role operationally. These aspects would have to be factored into the overall cost-benefit analysis and long-term financial planning in comparison with existing and alternative management solutions. There may also exist a need to introduce additional constraints or functionality capable of managing the storage during periods of prolonged CI, for example, periods where the CI is 'low' for several days. A point of consideration is that the CI metric currently used, as also used in [23], is an aggregated value for GB which considers total demand and generation. However, with a disaggregated localised metric that accounts for the influence of local demand, DG and DERs, there would be regular variation in the local CI in different regions. This would be driven by variation in weather conditions, installed capacities and demand requirements. Therefore, as GB transitions to 100% renewable generation, CI dispatch may prove more valuable for localised carbon offsetting supporting a cost-effective bottom-up net-zero approach.

5 | CONCLUSIONS AND FUTURE WORK

To conclude, in the decarbonisation of rural networks in Scotland, energy storage is set to be instrumental in supporting and facilitating the ongoing energy transition [35]. The work reported in this paper has developed a multi-functional battery control strategy that integrates constraint management with carbon-intensity linked control dispatch – carbon control – to support decarbonisation of rural distribution networks in Scotland.

The investigation has provided novel insights into the interplay challenges with multi-functional storage between constraint management and carbon control and into the potential for management of functional operational capacity constraints, to support local balancing through smaller scale, decentralised carbon management. In principle, this has the potential to mitigate the inherent issues with multi-functional storage and enhance the overall value of storage management solutions. The control strategy has been designed such that minimal physical measurements – which are readily available from existing monitoring equipment installed on primary transformers and through National Grid's online API – are required allowing for highly practical and cost-effective physical implementation. This is in support of the transition to 100% renewable rural networks that are self-reliant and 'carbon neutral', where increased self-sufficiency presents the opportunity to also adopt other attractive network management solutions including the use of intentional islanding (assuming appropriate control and protection schemes are implemented) to ensure security of supply, enhancing overall network resilience in remote regions which is considered an urgent priority in light of recent weather-related disturbances [36]. The development of flexible low carbon heating and transport solutions in addition to further uptake of distributed generation is expected to require enhanced management and has significant potential to support the proposed decarbonisation solution. As a result, there continues to be a need for future research in this space and this is further evidenced by [14].

Future research would involve further analysis of multi-functional storage dynamics and the evolving role of multi-functional storage with carbon control, where LCTs such as EVs and heat pumps would be introduced to the network and the subsequent impact on the dynamics and storage assessed. This would potentially raise additional challenges with storage sizing and capacity constraints over a prolonged period in the face of an evolving network. Providing suitable grounds to conduct a more focused assessment on the relationship between storage size and multi-functional dynamics. The CI-driven low carbon balancing could be further developed to include disaggregation of the CI to a more localised level and the long-term benefits assessed against other dispatch metrics when capacity limits are more active. Additionally, National Grid's CI two-day ahead forecasts could be used to predict dispatch actions and balancing requirements in advance to support flexibility planning. There is also scope for a more comprehensive assessment and review of multi-period optimal power flow dispatching techniques and the role of battery storage and carbon control in this setting.

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CONFLICT OF INTEREST

The authors have declared no conflict of interest.

DATA AVAILABILITY STATEMENT

Data sharing not applicable to this article as no datasets were generated or analysed during the current study

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