Impact of Low Inertia and High Distributed Generation on the Effectiveness of Under Frequency Load Shedding Schemes

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***Abstract*—The Under-Frequency Load Shedding (UFLS) scheme is an emergency measure in place to prevent system collapse in the event of a large generation deficit relative to demand at any moment in time. However, the effectiveness of traditional UFLS schemes may be compromised as network power flows change due to the growth of distributed generation (DG) and a reduction in system inertia. This study has shown some of the issues affecting the UFLS protection system with rising installed capacities of DG in the Great Britain power system. Simulation results show how the effectiveness of the scheme is challenged with current and future expected DG installed capacities and the risk of over shedding demand due to the scheme's current settings is evaluated. Many proposed improvements to traditional load shedding schemes are based on upgrades to network monitoring and communication systems, which are not yet fully available. This study evaluates more readily available solutions, including relocation of under-frequency relays and reducing the time delay of the scheme, which may provide interim improvements to the UFLS scheme, based on a case study in GB.**

***Index Terms*—under frequency load shedding, distributed generation, low inertia and frequency stability.**

I. Introduction

DURING extreme contingencies, i.e. unplanned events that are more severe than those that are normally secured against, the scheduled frequency response holding may be insufficient to cover demand, causing frequency to drop outside of operational limits. To prevent the system frequency from reaching under-frequency protection limits of generating equipment and suffering a complete frequency collapse, Under Frequency Load Shedding (UFLS) schemes are implemented to automatically shed demand to restore system frequency and allow a new equilibrium to be reached [1]–[3].

The motivation to decarbonize energy systems and the cost reduction of renewable energy technologies has significantly increased the share of energy production taking place at the distribution level [4], [5]. As electricity demand is increasingly supplied more locally, the effectiveness of the UFLS scheme is challenged, and its level of success becomes dependent on the demand and generation mix downstream of each UFLS relay, at the time of operation. Without visibility of distributed generation (DG), uncertainty is introduced into the amount of true demand on the system at any given time and, therefore, uncertainty in the net effect that automatic load shedding may have on the system frequency when activated. Furthermore, the automated scheme can be detrimental to the system frequency if the load block is exporting power to the transmission grid, or, it disconnects generation or demand assets providing frequency response.

In addition to centralized generation being displaced by DG, synchronous generation is being displaced by asynchronous, converter interfaced generation in both transmission and distribution grids, reducing rotational inertia which is an inherent property of synchronous machines. One well recognized impact of low inertia is changing frequency dynamics resulting in a higher rate of change of frequency (RoCoF) during a power imbalance [6]. As system frequency changes faster in a low inertia system, there is an increased risk that multiple stages of UFLS will be triggered before the previous stage has had enough time to operate. This can increase the risk of over-shedding demand, leading to an over-frequency situation, the loss of further generation and potential collapse of the system frequency [7].

A. Design of UFLS Schemes

Conventional UFLS schemes use frequency relays which measure the frequency locally and automatically compare it with a pre-determined threshold. The settings for load shedding and their design philosophy are mainly based on turbine-generator underfrequency limitations and power plant auxiliary performance. The scheme is generally implemented in stages to prevent excessive load shedding and to allow the frequency to recover before the next step. The total load shed, the full frequency range in which the scheme operates, the number of stages and the block size of each stage varies in different systems depending on the system characteristics. The relays are typically distributed throughout medium and high voltage distribution networks and isolate selected supply points and feeders in order to shed load [1], [8], [9].

So far, conventional UFLS schemes have, in the most part, proven to be effective and have generally succeeded in arresting frequency falls [3]. The conventional type of static scheme is simple to implement but is relatively inflexible and settings are hard-programmed into relays. The proportion of load being shed at each stage and the time delays between them are intended to be the same for every event.

Several updated UFLS schemes have been proposed in the literature. These typically use additional information and

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measurements to compute the amount of load to be shed and better suit the specific contingency. So called 'semi-adaptive' UFLS schemes typically measure RoCoF as well as the system frequency to differentiate between smaller and larger events. In this case, load can be shed earlier and the risk of over- or under-shedding is reduced. More advanced load shedding techniques have also been proposed. These fully adaptive or dynamic UFLS schemes typically estimate the event size using the capacity of the lost generation or use RoCoF and the generators swing equations to calculate the amount of load to be shed. However, many of the proposed techniques may present challenges when accounting for systems with a high penetration of converter fed generation and be reliant on online monitoring and communications [10]–[12]. At present, this level of monitoring and communications infrastructure is typically only available at the transmission level. Therefore, the schemes do not always account for a high penetration of DG. Or, they require improved measurement and communication infrastructure in the distribution network [10], [13], [14]. The rapid growth of DG is likely to require solutions to be implemented in the short-term.

B. Great Britain Case Study

The two most recent events which triggered the UFLS scheme in Great Britain (GB) occurred in 2008 and 2019. In both events, the operation of the 1st stage of the UFLS scheme did arrest the frequency fall. However, while the scheme succeeded in preventing a frequency instability, in both events the scheme did not operate as designed, prompting a review of the issues encountered. During the 2008 event, only 26 out of 91 LFDD stage 1 relays (48.8 Hz) operated as intended because the frequency was arrested at 48.795 Hz which fell within the relay design tolerance [15]. The second event occurred on August 9th 2019 when a single lightning strike hit an overhead transmission line, leading to the combined loss of two large generators totaling 1378 MW and an estimated total loss of between 1300 MW and 1500 MW of DG across the event due to operation of loss of mains and under frequency protection [16], [17]. The high penetration of DG had substantial ramifications during the event, by both contributing towards the loss of infeed (LoI), and reducing the net effect of the UFLS scheme. It was reported that 892 MW of demand was disconnected, yet the net demand reduction seen by the transmission system was only 350 MW [16], [17].

Many distribution areas have a DG capacity of >40% relative to peak demand and in some areas installed DG can exceed 100% of local peak demand – much of which is unobservable and uncontrollable by the network operators [5]. There has also been a lack of common protocols for recording DG data leading to uncertainty in the amounts and types of DG at various locations in the network, as well as their interconnection and disturbance response characteristics [5]. This study adds to previous assessments with an up-to-date and detailed analysis of the amounts and types of DG in the system at different voltage levels.

It has been acknowledged by the TSO (National Grid) [18] and one of the Distribution Network Operators (DNOs) [19] that the LFDD scheme in GB is less effective in arresting system frequency in low inertia conditions with high amounts of DG installed. However, appraisals of proposed solutions are yet to be published. As the impacts of asynchronous generation are already being faced, and complete redesign of the scheme to an adaptive or dynamic one may require more time, this study assesses the effectiveness of more readily available solutions. These are, (1) relocating relays closer to the bulk of demand, to avoid disconnection of DG connected at 33 kV, and (2), reducing the total operating time of the scheme, to improve the effectiveness of the scheme in events with high RoCoF.

TABLE I
LFDD OPERATING CRITERIA [20]

Frequency (HZ)	% Demand disconnection for each Network Operator in Transmission Area		
	NGET[1]	SPT[2]	SHETL[3]
48.8	5		
48.75	5		
48.7	10		
48.6	7.5		10
48.5	7.5	10	
48.4	7.5	10	10
48.2	7.5	10	10
48.0	5	10	10
47.8	5		
Total % Demand	60	40	40

II. MODEL DEVELOPMENT

A. Summary of the UFLS Scheme in GB

The Grid Code for GB requires DNOs to facilitate automatic low frequency disconnection of demand, i.e. the LFDD scheme. (Note that this paper uses the terms UFLS and LFDD interchangeably). The scheme has nine stages and the block size varies across each transmission area, as seen in Table I.

The relays are generally connected at 132 kV substations and are designed to trip the lower voltage side of the incoming 132 kV transformers or the outgoing feeders. According to the GB Grid Code, part CC.A.5, the maximum operating time for low frequency relays is 150 ms and the total operating time of the scheme, including circuit breaker operating time, should be less than 200 ms [19], [20]. The requirements for the scheme operating time apply equally to each LFDD stage, as seen in Table I. From a review of typical manufacturer data sheets, current generation 11 kV and 33 kV circuit breaker operating times are in the range of 55-60 ms [21]. This study assumes a circuit breaker opening time of 60 ms and relay operating time of 140 ms for today's system to model a scheme that is Grid Code compliant. The effect of reducing the operating time of the scheme is then assessed in Section IV-D.

B. DG and Demand Data

A key factor to study and plan for the efficient operation of a power system with high penetrations of DG is transparency

[1]National Grid Electricity Transmission
[2]Scottish Power Transmission
[3]Scottish Hydro Electric Transmission

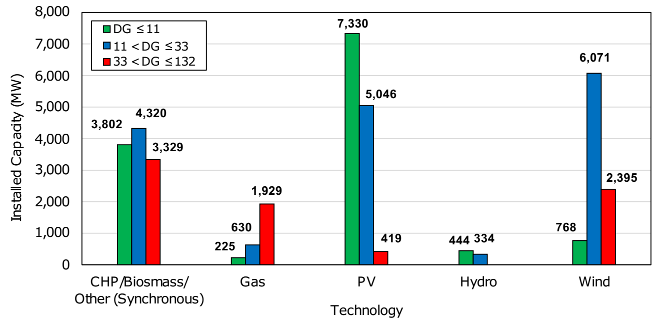

Fig. 1. Distributed generation technologies, installed at different distribution voltages in GB.

of network data. Each DNO in GB is required to produce a Long-Term Development Statement (LTDS) which documents some technical aspects of their networks. This work collects the LTDS data, addresses the discrepancies and groups the data to provide visibility into the types and amounts of DG installed at the various distribution voltage levels in GB. For further analysis on DG data in GB that is used in this study refer to [5]. Fig. 1 shows the installed capacity of various DG technology types installed at each of the distribution voltages in GB [5]. The LTDS data shows that the majority of wind generation is connected at 33 kV and solar PV has a high penetration at both 33 kV and 11 kV and below. As of 2019, there was approximately 12 569 MW of DG capacity installed at 11 kV and in low voltage networks and 16 600 MW of DG capacity installed at 33 kV.

C. Power System Model

To be useful in practical power system planning and operation - to allow both the study and the understanding of different phenomena such that causes of problems can be discerned and appropriate action by operators or planners informed - models should be as simple as possible but not too simple [22]. There will always be some degree of uncertainty regardless of how precisely different phenomena are modelled. It is very difficult to obtain accurate data for all parameters and it is rare to know the system's state with perfect accuracy at any given moment, particularly in respect of the distribution network on which, in most real power systems, there is very little monitoring. For the assessment of variation of system frequency in response to disturbances, on moderately sized island systems such as that in Great Britain, a single bus model usually suffices in respect of the main effects and assessment of the need for particular volumes of, for example, frequency containment reserve. Models with greater spatial detail are used to study conditions and faults that are known to give rise to risks of angular instability. Moreover, even a model that neglects the fastest dynamic phenomena is still very difficult to calibrate as there is considerable uncertainty around such factors as the frequency sensitivity of loads [23] and, as has been discussed above, the behaviour of DG. The approach used here to highlight the main issues around performance of LFDD follows that of the system operator in Great Britain, National Grid ESO, in its assessment of frequency response [24]. The

TABLE II
MODEL PARAMETERS

System Element	Parameter	Value	Reference
Responsive and Non-response SG	Excitation System	ESST1A	[26]
Responsive SG	Governor	IEEEG1	
	Primary Response	750 MW (Aug 9th Event)	[17]
Load Dynamics	Inertia Contribution	1.8 H	[27]
	Freq. Dependency Factor (exponent k_{pf})	1.2	
	Time Constant	0.2 s	
DG	Wind Turbine and Control Models	NERC DER_A and IEC 61400	[28], [29]
	Protection Settings	EREC G59	[30]

model developed for this study has been calibrated to represent the actual GB system based on the recent known disturbance event which triggered LFDD on August 9th 2019 [16], [17] and is described in Section I-B. The modelling approach used here is in line with a technical assessment of the LFDD scheme in the European network published by the European Network of Transmission System Operators (ENTSO-E), where an ad-hoc simplified frequency simulation model is used and verified against a known disturbance event [25].

The model, shown in Fig. 2, consists of a single bus, single area transmission network with wind, synchronous responsive and synchronous non-responsive generation. A 400/132 kV transformer supplies a ten-area distribution grid. Nine areas represent each stage of the LFDD scheme, and one area has the remaining system demand and DG which is unaffected by the scheme. All load is modeled as being connected at 11 kV and all power electronic interfaced DG (e.g. wind, solar PV and battery energy storage) uses a wind turbine model. Within the timescales with which our study is concerned – the first 30 s after a disturbance – it is reasonable to assume that the availability of wind or solar power is unchanged and the response of an inverter interfaced source is governed by the behaviour of the inverter. An LFDD relay is configured to trip the secondary low voltage side of either the 132/33 kV or the 33/11 kV transformer. The main model parameters are detailed in Table II and the following assumptions are also made:

- With the neglect of network branches and associated voltages drops or rises from the model, reactive power demands are assumed to be at unity power factor and busbar voltages at 1.0 per unit. Voltage dependency of loads is not considered.
- Secondary frequency response, i.e. frequency restoration reserve, is not implemented in the model as it will respond later than the timescales concerned in this study.
- Installed capacities of DG are according to the LTDS data and assumed to be split between the different demand groups associated with each LFDD stage in proportion to the amount of demand associated with that stage.

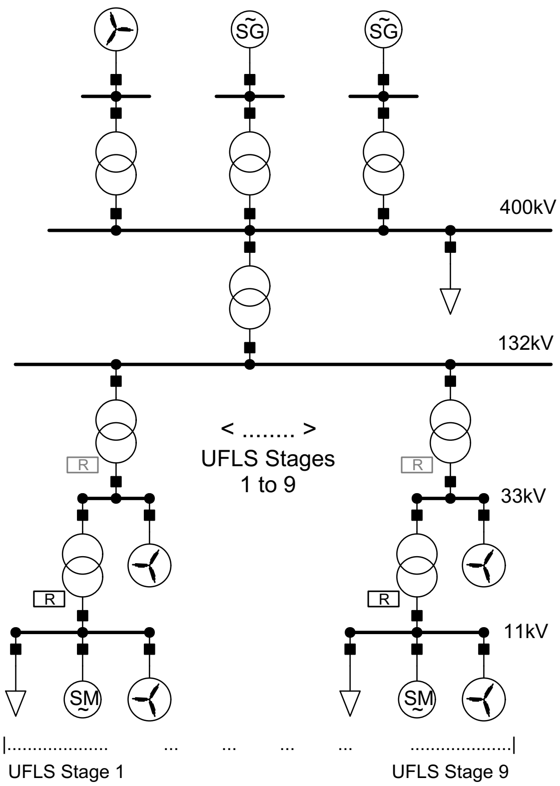

Fig. 2. Simplified network model.

In order to verify the system model, compliance checks have been performed to confirm performance against the Security and Quality of Supply Standards (SQSS) requirements [31]. The model has also been tested against known system frequency events and periods where RoCoF constraints were active and reported by the TSO.

III. Case Studies

The net transmission system demand is driven by the true demand, the installed DG capacity, and the DG output. The system frequency following a LoI event is driven by the active power imbalance and the system inertia. The following case studies are designed to vary the DG output and event size, while fixing true demand and inertia at credible low values, to observe the effects on the LFDD scheme with increasing DG.

An aggregated DG output, at any given moment in time is difficult to obtain due to the seasonal, diurnal and geographic variability of wind and solar PV technologies, as well as the lack of monitoring and observability of all types of DG in the distribution network. The approach taken here is to estimate a case where DG is very high, and close to their aggregate peak power, and then scale down the output. The 'very high' DG output has been estimated as a maximum based on [32]–[34].

The base-case or case 1 represents the system conditions of August 9th, the last event to trigger LFDD, and is used for model set-up. The base case represents moderate demand, high (40%) DG output and moderate inertia of 210 GVAs. To then test the LFDD scheme's effectiveness and the impact of operating with a high proportion of DG, periods of low demand and high DG output are studied in case 2 and case 3. For these cases, the true demand is fixed at the summer afternoon minimum for the years 2019 and 2026, respectively, as reported in National Grid's Future Energy Scenarios (FES) [35], as this is when distributed PV can be at its peak output. The FES indicates that demand continues to reduce until 2026 due to increased levels of energy efficiency with demand increasing thereafter as the use of energy for heat and transport begins to be electrified. The DG scaling factor is then increased from medium (20%), high (40%) and very high (60%) to assess the impact of varying DG output when true demand is low.

TABLE III
Modeled System Conditions

Case	True Demand	DG Installed Capacity $\leq$33 kV	DG Output	Net Transmission Demand
	MW	MW	%	MW
1	39,740	29,294	40	30,000
2.1	29,100	29,294	20	23,241
2.2	29,100	29,294	40	17,382
2.3	29,100	29,294	60	11,524
3.1	27,100	43,812	20	18,338
3.2	27,100	43,812	40	9,575
3.3	27,100	43,812	60	5,194

Case 2 uses the installed capacity of DG as of 2019 according to the LTDS data, and case 3 assumes that all the 'accepted' DG is built by 2026 and connected at the proposed voltage level. As the true demand is fixed, net transmission demand reduces with higher DG. At the same time, the system is operating with a low inertia, representing a high penetration of converter fed generation at both transmission and distribution levels. The pre-fault system inertia is fixed at 100 GVAs for cases 2 and 3, which is considered low for today's system [36]. While the national trend for total system inertia is reducing as synchronous machines are displaced with converter fed resources, it is assumed that inertia will not go below this value and the system operator will procure additional inertia via synchronous compensation in order to minimise curtailment of renewable generation [37]. However, in later years such as 2026 represented by case 3, the percentage of the year that will be spent at lower inertia is higher. Therefore, there is increased exposure to the risk of ineffective operation of the LFDD scheme. For each case, three LoI events are simulated: a loss of 2.5 GW, 4 GW and 6 GW. To test a realistic worst case scenario, the LoI is modeled as the loss of both synchronous and asynchronous transmission connected generation. As a result, the system's inertia is reduced by the loss. Table III shows a summary of the study cases.

IV. Results and Discussion

The main performance indicators considered here for assessing the suitability of the LFDD scheme are: the number of LFDD stages being triggered, the amount of true demand being disconnected, and the net effect the LFDD action has on the system frequency. The sub-sections below describe the simulation results, and value of solutions proposed, with comparison and summary of results at the end of the section.

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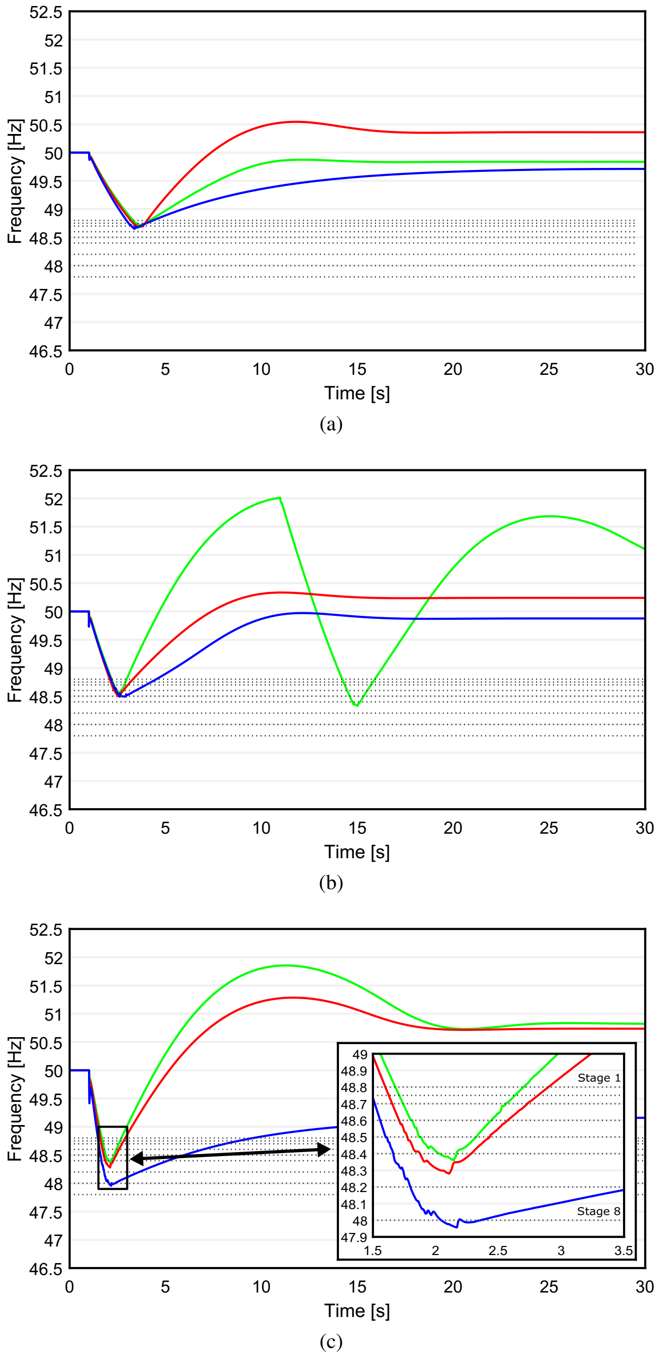

Fig. 3. System frequency for 2019 cases comparing DG output — Case 2.1 — Case 2.2 — Case 2.3, at each loss of infeed event (a) 2.5 GW. (b) 4 GW. (c) 6 GW.

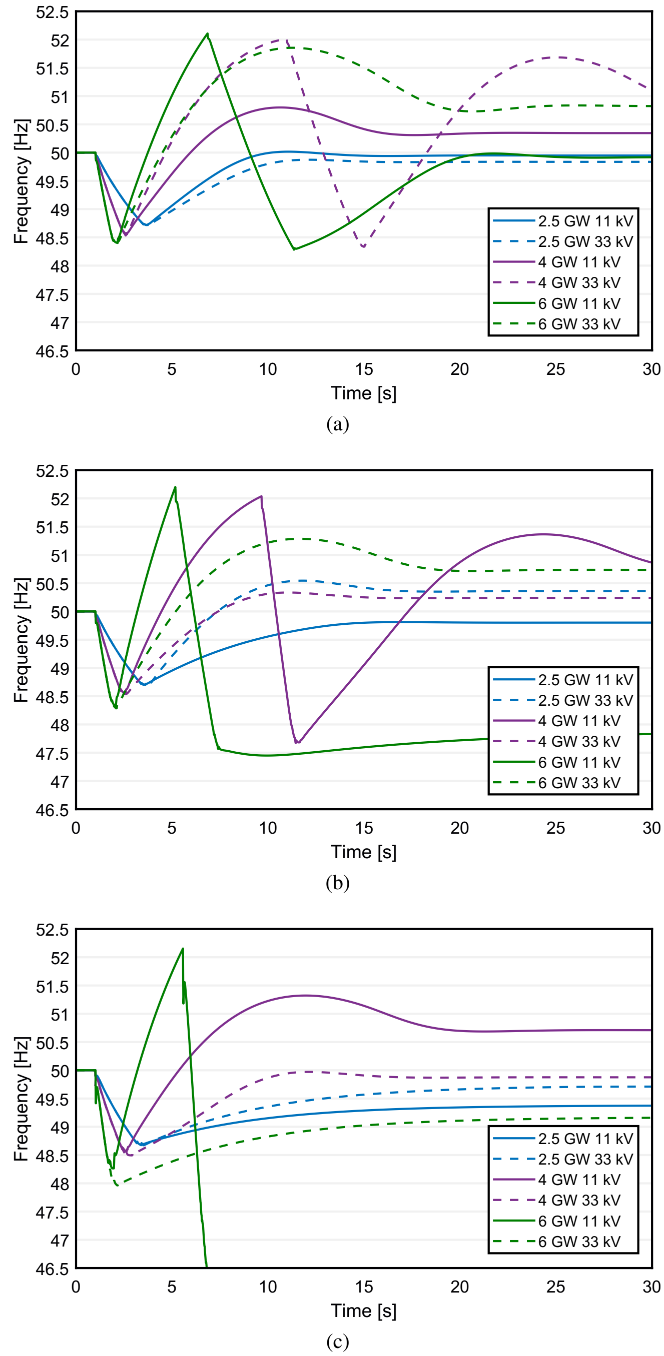

Fig. 4. System frequency for each of the 2019 cases comparing relay location for each loss of infeed event. (a) Case 2.1. (b) Case 2.2. (c) Case 2.3.

A. LFDD Effectiveness with Increasing DG Output

Fig. 3 compares the frequency trace for each sub-case with the same LoI event for 2019. The figure shows, as horizontal dashed lines, the frequency thresholds at which the different stages of LFDD operate. In each case, the LoI event occurs 1 s into the simulation. Cases 2.1, 2.2 and 2.3 have an aggregated DG output of 20%, 40% and 60% respectively, these are each compared with an LoI of 2.5 GW (Fig. 3(a)), 4 GW (Fig. 3(b)) and 6 GW (Fig. 3(c)). All relays are located at 33 kV as is presently the case. The frequency traces show that, immediately following the disturbance event, the system enters a state of degrading frequency (RoCoF <0 Hz/s). The generator inertial response and primary frequency response are insufficient to arrest the frequency drop and equalize the active power imbalance, and LFDD relays are activated. When the system has a higher penetration of DG, more demand is required to be disconnected for the same LoI event due to a reduced net effect seen at the transmission system, as DG increasingly supplies the demand locally. For most cases in 2019, one additional stage of LFDD is reached for each step increase in DG output. Thus, the DG output at the time of a disturbance can be seen to have a significant effect on the number of demand customers disconnected during an LFDD event, particularly if high DG output coincides with low true demand. The effects of increasing DG output in 2019 (case 2) are exacerbated in 2026 (case 3) as net transmission demand is reduced, together with a rise in DG installations. For most cases in 2026, more than one additional LFDD stage is reached for each step increase in DG output, resulting in significant additional loss of demand. The results for 2026 (case 3) can be observed in Fig. 7.

Following the disconnection of enough true demand to arrest the frequency decline, the system transitions to a state of recovering frequency (RoCoF $\geq 0\,\mathrm{Hz/s}$) before stabilizing at a steady state. Recovery to 50 Hz depends on there being sufficient generation available to re-accelerate the system from a low frequency. Whether or not the system overshoots depends on the speed of governor response and the margin for rapid, automatic reduction in output in the event of an over-correction of a negative imbalance into a positive one.

B. Relocating LFDD Relays from 33 kV to 11 kV

To assess the benefit of relocating LFDD relays from their current location at 33 kV to the proposed location at 11 kV, each case is run with identical conditions at each relay location. Fig. 4(a)–(c) show the results for each scenario of study case 2. For most of the cases, as the DG output increases, a benefit is observed with relays located at 11 kV, due to the 33 kV generation remaining connected, resulting in a greater net effect of demand disconnection seen at the transmission system. Therefore, fewer LFDD relays, and less associated true demand, are required to be disconnected to arrest the system frequency. For the same reasons, the net effect that the demand reduction has at each relay location also has a significant effect on the post-LFDD frequency. Relocating the relay can result in excessive demand being disconnected. For example, observing Fig. 4(c), case 2.3 for a 6 GW loss of infeed, when relays are located at 33 kV, seven LFDD stages are triggered resulting in 50% of true demand disconnection, assuming all relays operate. However, for the same case with relays at 11 kV, six LFDD stages are triggered but result in an excessive amount of load being disconnected and the post-LFDD frequency overshoots and exceeds 52 Hz. This is significant as, in accordance with the Grid Code, all generation in GB is no longer required to remain connected when system frequency exceeds that threshold and generator protection may activate [20].

C. Effect of Very High RoCoF

In many cases studied, excessive demand is disconnected during operation of the LFDD scheme and an over-frequency situation occurs. In a low inertia system, when a disturbance occurs with a high LoI, RoCoF will be high and there is a significant risk that multiple LFDD frequency thresholds are reached before the previous stage has had time to operate.

Fig. 5 shows a zoomed area around the frequency nadir of case 2.1 with 20% DG output, 4 GW LoI and relays at 33 kV. The horizontal dashed lines represent the LFDD frequency threshold and the corresponding marker is the time at which

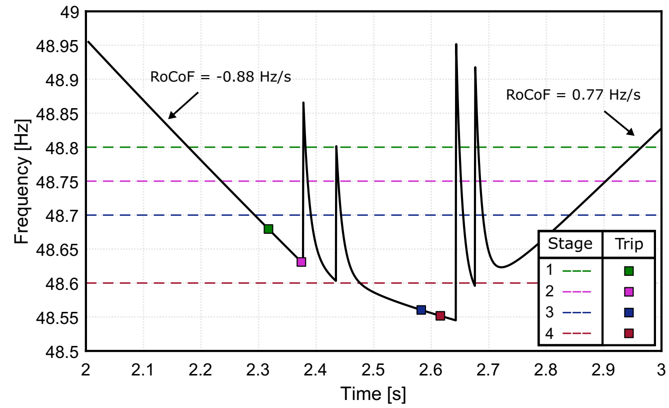

Fig. 5. Modelled frequency as measured by LFDD relay, zoomed area around frequency nadir for Case 2.1 (4 GW LoI, 33 kV) with 140 ms relay delay time.

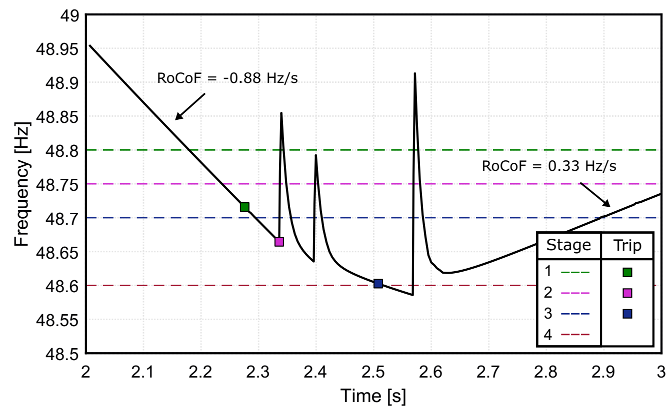

Fig. 6. Modelled frequency as measured by LFDD relay, zoomed area around frequency nadir for Case 2.1 (4 GW LoI, 33 kV) with 100 ms relay delay time.

the tripping signal is sent to the circuit breaker for each stage (i.e. it does not include the circuit breaker opening time). Stage one and two are triggered before the operation of stage one. As the stage one and two loads are disconnected, the frequency measurement of the stage three relay is reset. Subsequently, frequency thresholds of stages three and four are breached, and tripping signals are sent. In this case, three stages of load disconnection is sufficient. However, as the stage four trip signal is sent before the operation of stage three, too much load is shed and the frequency rises quickly towards 52 Hz with a positive RoCoF of 0.77 Hz/s. In cases more extreme than those shown in Fig. 5, it is common for three consecutive stages to trigger in very short time periods.

As observed in Fig. 5 and Fig. 6, there is an apparent instantaneous spike in the modelled frequency as seen by the LFDD relay. At the point when the load is disconnected, there is an instantaneous change in the phase angle at the location of the load disconnection, which causes this observed frequency spike before settling back to its trajectory. This spike in the frequency can cause the frequency measurement of subsequent stages to be reset, as the modelled frequency momentarily goes back above the frequency threshold and restarts the time delay of the measurement period. The change in phase angle, in reality, would be greater in the locality of the load disconnection than at other locations. Given that LFDD relays would be subject to measurement and timing variations and are distributed across a large area, in practice not all relays would see the same frequency or respond in exactly the same way. Hence, spikes observed on the actual network would likely be smaller than suggested by the simulation which models all of the load disconnection as a single switching action. The time at which each stage of the scheme operates depends on the local frequency being measured by each relay, and that the frequency signal remains below the threshold for the duration of the measurement window. In practice, this will also depend on the way the frequency is calculated by the relay and any filtering that is implemented to account for noise or spikes such as these. Therefore, due to the way the system is being modelled, in some cases in this study the relay action is likely to be delayed to some extent relative to how an LFDD relay may perform in reality.

D. Reducing LFDD Scheme Operation Time

To reduce the risk of over shedding demand and crashing through multiple stages when a high RoCoF occurs, the operating time of the LFDD scheme can be reduced. A report by ENTSOE recommends that the total tripping time of load shedding relays is less than or equal to 150 ms [25]. The LFDD scheme in Taiwan has a 100 ms time delay [38], indicating that lower time scales are achievable. In practice in GB, it may not be possible to reduce the opening time of the circuit breakers used in distribution networks. However, using modern relays such as [39], a minimum relay measurement time of 100 ms can be achieved. The scenarios are re-run here with the relay operating times reduced from 140 ms to 100 ms, to assess the benefits. Both cases have a circuit breaker opening time of 60 ms.

Fig. 6 shows the same case as Fig. 5, except the relay operating time is reduced to 100 ms. It can be seen that the faster triggering time assists in managing the high RoCoF, LFDD stage 4 does not operate and the frequency rise post LFDD action is much slower. Results for all cases comparing the reduction in relay operating time are shown in Section IV-E.

Observing the LFDD settings, The first three frequency thresholds are 0.05 Hz apart, allowing little space between them and may be considered prone to the risk of unintended operation due to high RoCoF. Having a higher number of small load blocks such as the current scheme can mitigate against over shedding. However, this relies upon a sufficiently low RoCoF to ensure that the frequency does not fall quickly through each block.

As the scheme implements fixed frequency thresholds ($f_{\mathrm{stage,n}}$) and time delays (t_{d}), the operating time of the scheme and the space between stages creates a maximum allowable RoCoF ($RoCoF_{\max}$) such that, the influence of the previous stage is felt prior to triggering a subsequent stage. The $RoCoF_{\max}$ is determined by the time taken for the frequency to drop between adjacent stages that are closest to each other, and the time delay for the relay frequency measurement ($t_{\mathrm{d}}(\mathrm{s})$), according to (1). Table IV shows $RoCoF_{\max}$ required to prevent 'stage crashing' for the current scheme, for a reduced time delay of 100 ms, and for another option of redistributing the load shed under stage 2, to ensure that all stages have at least 0.1 Hz between them. The authors note that, if this RoCoF limit is exceeded it does not guarantee that over shedding will occur, but it is possible depending on the system and event conditions.

TABLE IV
MAXIMUM ALLOWABLE ROCOF REQUIRED TO PREVENT 'STAGE CRASHING' FOR THE CURRENT SCHEME

	$RoCoF_{\max}$
Current Scheme (Grid Code, $t_{\mathrm{d}} = 150\,\mathrm{ms}$)	0.33 Hz/s
Current Scheme with reduced delay ($t_{\mathrm{d}} = 100\,\mathrm{ms}$)	0.5 Hz/s
Adjusting Stage 2 ($f_{\mathrm{stage1}} - f_{\mathrm{stage2}} \geq 0.1\,\mathrm{Hz}, t_{\mathrm{d}} = 100\,\mathrm{ms}$)	1 Hz/s

$$RoCoF_{\max}\left(\frac{\mathrm{Hz}}{\mathrm{s}}\right) = \frac{f_{\mathrm{stage1}}(\mathrm{Hz}) - f_{\mathrm{stage2}}(\mathrm{Hz})}{t_{\mathrm{d}}(\mathrm{s})} \quad (1)$$

E. Results Summary

Fig. 7 summarise all cases with a relay delay time of 140 ms, comparing results for 33 kV and 11 kV relay locations and showing the effects of different sizes of LoI for different levels of true demand and DG output. Fig. 7 shows the final steady state frequency measured at 29 seconds after the event and the percentage of true demand disconnected for each case.

The post-LFDD frequency is highly variable and ranges between 48.27 Hz and 52 Hz. This shows that, should the system be subjected to a major disturbance during low demand and low inertia conditions, the effectiveness of the LFDD scheme in recovering the frequency to within reasonable limits is uncertain. When under-shedding occurs, resulting in a low frequency, the system is more vulnerable to subsequent or follow-on disturbances and the TSO will require access to more power reserves to bring the frequency back up to nominal. When over-shedding occurs, resulting in a high frequency, there will be a reliance on generator control systems to quickly reduce power output. However, the ability to contain the frequency will depend on the controller response times and droop settings, which will depend on the generation technology. Some wind farms have demonstrated effective and fast high frequency response [40]. In addition, the minimum stable operation of synchronous generators must be respected and therefore sufficient foot-room may not be available if they are dispatched close to their minimum operating point.

The GB Grid Code allows disconnection of transmission connected generation above 52 Hz. However, specific protection settings and delays are not public and the authors' discussions with a number of industry experts suggests that they will vary considerably for different generators depending on age and technology type. With regard to the remaining distributed generation (post LFDD action), the G59 connection standards [30] define the over frequency protection of generators to be set at 52 Hz at which point they are required to trip, and these plants are typically not frequency responsive. In a low inertia system, where significant LFDD stage over-shedding occurs causing a high frequency, there is much uncertainty among the experts to whom the authors have spoken regarding

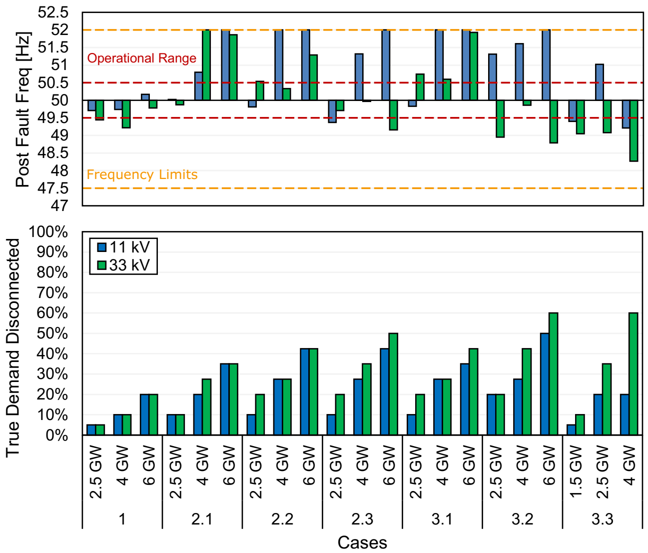

Fig. 7. Final post-event steady state frequency and the percentage of true demand disconnected for each case (140 ms).

TABLE V
SUMMARY OF 2019 RESULTS

Number of Cases (total of 9)	140 ms		100 ms	
	33 kV	11 kV	33 kV	11 kV
Outside of operational range	5	7	5	5
Outside ±1 Hz	3	5	2	3
≥ 52 Hz	1	4	0	3
Requiring 1 less LFDD stages[1]	-	5	3	7
Requiring ≥ 2 less LFDD stages[1]	-	0	0	1

TABLE VI
SUMMARY OF 2026 RESULTS

Number of Cases (total of 9)	140 ms		100 ms	
	33 kV	11 kV	33 kV	11 kV
Outside of operational range	8	8	8	7
Outside ±1 Hz	4	6	4	4
≥ 52 Hz	0	3	0	2
Requiring 1 less LFDD stages[1]	-	7	1	9
Requiring ≥ 2 less LFDD stages[1]	-	4	0	4

how the system as a whole would respond. Nonetheless, such conditions could present a risk of blackout due to the tripping of too much generation relative to demand.

The effectiveness of the scheme is also judged by the amount of demand that is disconnected. The less true demand disconnected, the lower the societal impact of the event. While the LFDD scheme's priority is to prevent collapse of system frequency, ideally it should not disconnect more customers than required. Furthermore, when there is a larger proportion of the whole system that is unsupplied, it may require more effort to restore.

To assess the value of the two potential solutions, i.e. relocating relays to 11 kV and reducing the relay time delay to 100 ms, the results are summarized in Table V and Table VI for comparison with the current implementation of the scheme.

Regarding the post-LFDD frequency referring to the top half of Fig. 7 and the first three rows of Table V and Table VI , the following observations are made:

- An increased number of cases settling further from nominal frequency is observed in 2026 compared with 2019.
- Relocating relays to 11 kV increases the tendency to over-shed demand. This is due to an increase in net load disconnection per block for high DG outputs. However, the possibility of over- or under-shedding exists with either relay location.
- In the cases studied, reducing the relay operation time to 100 ms reduces the risk of over-shedding.

Regarding the amount of demand disconnection required referring to the lower half of Fig. 7 and the last two rows of Table V and Table VI, the following observations are made:

- In general, due to the increased net demand disconnection, relocating the LFDD relays closer to the demand at 11 kV results in fewer demand blocks needing to be disconnected compared with 33 kV, improving the effectiveness of the scheme.
- Reducing the relay operation time to 100 ms also improves the effectiveness of the scheme, increasing the number of cases where fewer LFDD stages are triggered. However, the effect is not as great as relocating relays.
- The greatest improvement is seen when applying both relocation of relays and reducing the operating time.
- For both relay relocation and reducing scheme operating time, the improvements in the scheme's effectiveness are greater in the 2026 cases than in those for 2019.

V. CONCLUSIONS

This paper describes simulations of credible 2019 and 2026 scenarios in GB under which LFDD would be triggered. The simulations show that the effectiveness of the LFDD scheme in GB is already compromised by the growth in DG and asynchronous resources at all voltage levels, addressing the possibility that the implementation of LFDD in Britain and of UFLS more generally is no longer fit for purpose.

Many improvements to UFLS schemes that are proposed in the literature are unlikely to be ready for implementation in the current GB power system. This work provides a preliminary assessment of some of the more readily available solutions. It is shown that relocating LFDD relays from 33 kV to 11 kV and reducing the total operating time can improve the effectiveness of the current scheme.

The last major review of LFDD in GB was conducted in 2001 [2]. A forward-thinking review of LFDD specification in GB is required to ensure a robust and efficient scheme is in place which offers dependability at least cost, while minimizing societal impact during triggered events in the future. It may be necessary to amend the codes governing the implementation of LFDD in two stages: in the near-term to make LFDD more suitable for the system changes that have already occurred, considering solutions such as those assessed in this study,

[1]Compared with the current implementation for each base year (relays at 33 kV and t_d = 140 ms)

and then, in a second stage following the conduct of suitable research and testing, to make the system more robust for the longer term. The LFDD scheme should be designed such that it can be relied upon in a wide range of system operating conditions (ideally all operating conditions). In other words, it can be implemented, and, to some extent, forgotten about save for periodic review to re-assess its suitability for contemporary and future system conditions.

The kinds of simulations of different options for configuration of LFDD/UFLS described in this paper are necessary and practical starting points to inform revision of a scheme's implementation, but they are not sufficient. Analyses with more detailed models capturing the spatial distribution of demand and of generation of different types, including DG, and variations in the voltages (and hence magnitudes of loads) and measured frequencies (leading to potential differences in whether and when different stages of UFLS would be triggered) should be undertaken for a wide variety of operating conditions in order to build confidence in any new configuration. Furthermore, the usual testing of relays with artificial signals should be carried out. However, proof of the effectiveness of a scheme is typically only available when major disturbances - usually rare - happen. An important lesson of the August 2019 event in GB - the outcome of which was not as bad as it might have been - is that preparedness is important and that the configuration of defence schemes such as UFLS should be reviewed on a regular basis and before they might be shown to be ineffective.

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