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What does the power outage on 9 August 2019 tell us about GB power system

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Abstract

The power outage on 9th August 2019 affected over 1 million customers in England and Wales and caused a major disruption to other critical infrastructures. While the power system responded exactly how it was designed to in response to an unsecured (N-2) event, it has uncovered important fault lines which may significantly affect reliability of the system in a near future.

Over the last 10 years or so the GB power system has changed quite rapidly due to the decarbonisation drive and penetration of smart grids technologies. Hence it is increasingly difficult for the ESO to fully monitor, model and control the whole system and therefore the probability of hidden common modes of failures has increased. This would suggest that it might be prudent to strengthen the old (N-1) security standard by providing extra security margin.

There were also other issues highlighted by the outage. Embedded generation reached such a high penetration level that it cannot be treated any longer as negative demand. Traditional under-frequency load shedding disconnects indiscriminately all customers on the disconnected feeders, including embedded generation and frequency response units, hence reducing its effectiveness. The ability of critical infrastructures and services to ride through the disturbances has to be closely monitored and tested.

Finally, we have concluded that, in GB at least, power outages matter only if they affect critical infrastructures, especially transport, in London and the surrounding areas.

Keywords power blackouts, UK electricity, security of supply

JEL Classification L94

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1 INTRODUCTION

Reliable supply of electricity is of fundamental importance for any modern society and economy, so it is no surprise that the power outage on 9th August 2019 that affected over 1 million customers in England and Wales and caused a major disruption to other critical infrastructures (especially rail services in the South of England including London) was a major news item and sparked wide-spread discussions about who is to blame. Power outages are like stress tests exposing strengths and weaknesses of the power system as the whole and its constituent elements and other critical infrastructures connected to it so our main aim is to consider the title question: what does the power outage tell us about the state of GB power system.

In this paper, we will make extensive use of the following reports: (Ofgem, 2020), (NGESO, 2019b), (E3C, 2020) but our main intention is not to repeat the findings contained in those reports but rather draw more general conclusions about the current state of GB power system and what are the problems that need to be addressed. This is especially important in view of the goal of net-zero greenhouse gas emissions by 2050. To achieve that target, the power system will have to change even more rapidly than it has over the last 10 years so any weaknesses exposed by the outage will have to be urgently addressed.

In Section 2 we will provide an overview of the mechanisms by which power systems are kept secure when power stations trip. Then we will describe the event itself in section 3, and in section 4 we will describe the impact the outage had on connected critical infrastructures and services. Some of the power outages that happened in GB over the last 20 years have attracted a wide media coverage and public attention while others have not. Hence in section 6 we will address the question when do power outages matter. In section 5 we will try to answer the title question of what does the outage tell us about the state of power system and we will conclude in section 6.

2 HOW TO MAINTAIN A RELIABLE SUPPLY OF ELECTRICITY IN PRESENCE OF GENERATION FAILURES

Whenever a blackout/outage happens, the first reaction of media and people is: it should have never happened. However it is important to appreciate that it is never possible to have 100% reliable power system and outages will always happen. As reliability is expensive, the main question is what is the cost-effective level of system reliability we require. Most media and public attention is devoted to transmission-level outages, like the one on 9th August, as they affect hundreds of thousands or even millions of people. But actually, by far the most common outages are at the distribution level, e.g. caused by a digger hitting an underground cable. As distribution networks are usually radial, i.e. tree-like, a cable failure at a certain point is local, i.e. it will disconnect only the customers connected to the affected feeder below that point. By comparison, outages at the transmission level, caused by failures of the transmission network or transmission-connected power stations, are quite rare but disconnect more customers as they affect large areas of a country. It is only human to be more concerned about very rare but big events rather than more frequent but small ones.

In this section, we will outline the main principles of maintaining the reliability of a power system and means of achieving it. We will concentrate on maintaining the balance of power, i.e. continuity of supply when a power station suddenly trips. We will not consider the effects of transmission network failures.

2.1 Power-frequency mechanism and the role of inertia

Due to a lack of large scale energy storage, the power balance in a system must be held at all times, i.e. the amount of power produced must be equal to the amount of power consumed. If there is any imbalance, it will show itself by changes in power system frequency, and in this subsection, we will explain this mechanism.

Frequency in a power system (50 Hz in GB) is determined by the speed of synchronous generators which convert mechanical power providing by turbines (steam, gas, hydro) into electrical power in traditional power stations.

Synchronous generators are kept in synchronism by electromagnetic forces, i.e. they rotate at the same speed[1]. This mechanism can be visualised in a cartoon form in Figure 1. A number of parallel cars (representing generators) pull up a hill a big wheel (representing the combined power system load). The strings linking the cars to the wheel represent electromagnetic forces. The links ensure that the cars run at the same speed (frequency) in the steady-state, which means that the power system frequency is the same everywhere[2]. If there are some bumps on the road, which represent small changes in power system demand or generation, the balance of forces is disturbed and frequency will change. System inertia stores kinetic energy, so it provides a buffer to any disturbances, releasing additional energy by slowing down when there is a deficit of power or storing extra energy by speeding up when there is a surplus of power. The bigger the system inertia, the lower frequency changes resulting from power balance disturbances. As demand changes all the time, frequency undergoes continuous fluctuations around 50 Hz. The task of Electricity System Operator (ESO) is to make sure that frequency is kept within the statutory limits set out by National Electricity Transmission System Security and Quality of Supply Standard (SQSS, 2019).

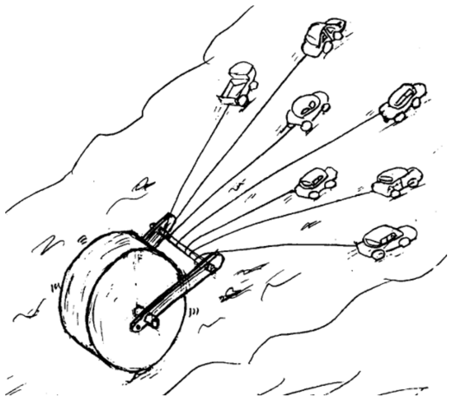

Figure 1 Cartoon visualisation of power-frequency mechanism[3].

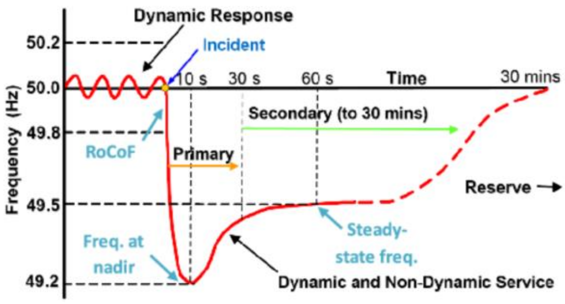

Figure 2 Illustration of frequency response (Teng, 2015).

Let us now consider what happens when a power station suddenly trips and frequency starts to fall. Figure 2 shows a typical trace of the frequency, also illustrating specific terms used in the paper. The initial speed with which frequency falls is referred to as Rate of Change of Frequency (RoCoF) and it is proportional to the size of the disturbance ΔP and inversely proportional to the inertia constant H:

$$\text{RoCoF} \propto (\Delta P/H) \tag{1}$$

Initially the power imbalance is covered entirely from the kinetic energy stored in system inertia and it is proportional to RoCoF – see (1). The fall in frequency is sensed by turbine governors so that, after a few seconds

[1] To be more precise they rotate at the same *electrical speed* which determines the frequency. The *mechanical speed* of rotors will depend on the number of poles of a generator. A two-pole rotor will rotate at 3000 revolutions per minute (rpm) to produce 50 Hz power, a four-pole rotor will rotate at 1500 rpm etc.

[2] Frequency is the same everywhere only on average. The strings linking the cars represent electromagnetic forces which exhibit an elastic spring-like behaviour. Hence, if there is a disturbance (e.g. a bump on the road), the balance of forces is disturbed and the speed (frequency) of individual cars (generators) will oscillate around the average speed (frequency).

[3] This cartoon has been taken by the author a long time ago from a National Grid presentation but unfortunately the exact source of it has been lost in the mist of time, for which the author apologises and expresses a gratitude to the anonymous author for the excellent cartoon.

delay[4], the turbines start to react increasing their power output. Usually *droop control* is executed, i.e. the power increase is proportional to the frequency deviation Δf from the nominal frequency. This reduces the slope of frequency changes df/dt[5] and continues until eventually the turbines cover the whole power deficit ΔP, and frequency stabilises at a steady-state value after a dip called the *frequency nadir*. Generally, the bigger system inertia H, the smaller RoCoF and frequency nadir. On the other hand, stronger droop control of the turbines reduces the deviation of the steady-state frequency from 50 Hz and also the nadir. The control process is referred to as *primary frequency response* - it is fully automatic and all generators synchronised to the grid must participate in it.

The steady-state frequency is less than 50 Hz as some energy stored in inertia has been taken off to cover the initial power deficit. The task of returning to 50 Hz is referred to as the *secondary frequency response* and it is initiated and controlled centrally by SO. It is much slower than the primary frequency control. Usually, only selected generators contribute to it. In order to maintain system stability, System Operator has to keep an appropriate amount of fast-responding *primary frequency reserve* and slower *secondary frequency reserve*.

It is essential to consider the impact of renewable generators on the system frequency response. Generally, wind and solar PV power stations do not participate directly in frequency control as they could provide only regulation down but not up, unless they operate part-loaded. Also, they do not contribute to the system inertia as they are connected to the system by power electronics devices, called converters[6], rather than synchronous machines. Consequently, the system inertia has been dropping for years in GB and other countries as the penetration of wind and solar power increases. Reduced inertia results in a bigger RoCoF and frequency nadir and therefore can have serious consequences for system security. This issue is further discussed in 5.

Ensuring an adequate provision of frequency response so that frequency stays within the statutory limits for any reasonably-expected contingency (so-called Secure Event) is one of the main tasks of the ESO. In doing so the ESO has to take into account the influence of changing system inertia which may change quite radically throughout the day – see Figure 3– and which is not easily measured. Mandatory Frequency Response is provided from synchronised Balancing Mechanism[7] (BM) units under Grid Code obligations. The ESO also has a large variety of commercial frequency response contracts provided by generation, demand and storage, both participating and non-participating in Balancing Mechanism. The cost of providing frequency response in 2019/20 was £152M (NGESO, 2020b).

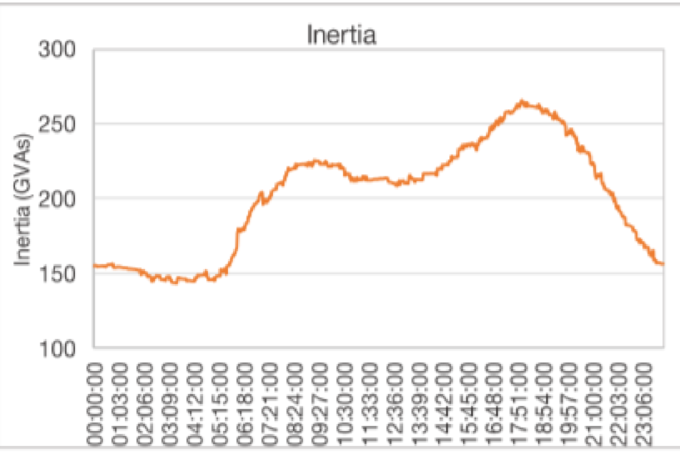

Figure 3 Daily inertia profile (NGESO, 2020a)

Table 1 shows the amount of frequency reserve at the time of power outage on 9 August 2019. Dynamic frequency response is a continuously provided service used to manage the normal second by second changes on the system. Static response is usually a discrete service triggered at a defined frequency deviation.

[4] The turbine governor and the turbine itself can be modelled by first or higher-order order lag systems which means that they cannot react instantaneously to the changes in in frequency.
[5] RoCoF is the initial rate-of-change-of-frequency after a disturbance while the slope df/dt changes all the time. RoCoF is equal to df/dt only initially, before the droop control of turbines is activated.
[6] A converter is a power electronics device that converts AC electricity into DC or DC into AC.
[7] The Balancing Mechanism is one of the tools used by the ESO to balance electricity supply and demand close to real time.

Table 1 - Frequency reserve held on 9 August 2019 (NGESO, 2019b)

Service	Provider type	Lower Frequency response held (MW)	
		Primary response	Secondary response
Dynamic – Generation (Mandatory response)	BM	284	325
Dynamic – Firm Frequency Response	BM & Non-BM	259	270
Dynamic – Enhanced Frequency Response	BM & Non-BM	227	227
Static – Firm Frequency Response	Non-BM	21	261
Static – Low Frequency Response through auction	Non-BM	31	31
Static - Interconnectors	BM	200	200
Total		**1022**	**1314**

2.2 SQSS

In GB, reliability standards are formalised in National Electricity Transmission System Security and Quality of Supply Standard (SQSS, 2019) and the task to enforce them falls to the Electricity System Operator (ESO) and other network operators. The SQSS requires the operation of the national electricity transmission system such that it remains secure following the occurrence of any one of a set of potential faults / contingencies (Secured Events) under prevailing system conditions.

To simplify the industry jargon used in SQSS, the system should remain secure following any (N-1) event, i.e. a loss of a largest single infeed which is either a single large generator, with a single mode of failure such as a single connection to the transmission system, or could be two or more smaller generators that are separate but are connected to the rest of the system through an asset treated as a single Secured Event (for example a double circuit overhead line or busbar). Normally it is Sizewell nuclear station at 1,260 MW but, if it is not operating as it was the case on 9 August, it is an interconnector at 1,000 MW. The SQSS anticipates that only one Secured Event would happen at any one time and does not assume multiple Secured Events occurring simultaneously, i.e. (N-2) or more events. The (N-1) standard is a common-sense engineering rule, which is universally accepted around the world, and follows from a consideration that the probability of two power stations failing independently and at the same time is very low and securing against it would be prohibitively expensive.

For the system to remain secure after a contingency, the amount of fast primary reserve held must be higher than the highest anticipated single infeed loss. Table 1 shows that the primary frequency reserve on 9 August 2019 was 1022 MW, i.e. just 2.2% above the 1000 MW of maximum infeed loss anticipated.

2.3 Taking into account the reaction of embedded generation

When identifying the largest infeed loss, the ESO must also take into account the effect of any consequent infeed losses in embedded generation[8]. The reason for that is that any embedded generation must be equipped with Loss of Mains protection which disconnects a generation plant from distribution network in the event of a loss of supply to the network (islanding) to prevent operation and safety-related problems. However, when there are large disturbances at the transmission level causing fast frequency and voltage changes, they could be wrongly interpreted as Loss of Mains by the protection of embedded plants which would disconnect them. Hence the ESO must make sure that a Secured Event would not activate Loss of Mains protection.

There are two main types of Loss of Mains protection: Rate of Change of Frequency (RoCoF) and Vector Shift. RoCoF works on the principle that if a part of a distribution network is islanded, frequency will change rapidly due to low inertia of that part of the network and a large imbalance of power. The RoCoF settings of embedded generators are specified by ENA Engineering Recommendations and are not uniform but depend on the size, point of connection, and date of commissioning (WPD, 2018). However the ESO assumes that the RoCoF limit is set at a historical value of 0.125 Hz/s and seeks to ensure that the system is configured in real-time in such a way that the limit is not breached for a Secured Event. This is achieved by dispatching traditional generation (and thereby increasing inertia) while reducing imports or renewable generation (with the former being more economic than the latter), management of response or reduction in the size of the potential largest infeed loss. The cost of

[8] We will use interchangeably the terms embedded or distributed generation to denote generation connected at the distribution level.

managing RoCoF in 2019/2020 was £210m (NGESO, 2020b). There is an ongoing Accelerated Loss of Mains Change Programme to replace the protection settings of embedded generation to make them less sensitive to transmission system disturbances, and increase RoCoF to 1 Hz/s, but the program is due to be completed only in 2022.

Vector Shift protection detects sudden changes in the mains voltage angle and it reacts quickly to changes in network impedance which often occur during islanding. However Vector Shift protection has been also found sensitive to short-circuits such as those accompanying lightning strikes. The ESO must therefore assesses the risk and probability of a Secured Event, the cost to secure and the likely level of Vector Shift. Based on this assessment the ESO will secure for the potential cumulative effect of vector shift (e.g. following a transmission fault) and infeed loss where it considers it appropriate to do so.

2.4 Load shedding

While a failure of two or more power stations is a rare event (the previous time it happened in GB was in 2008 – see section 6.1), it nevertheless may happen so the power system must have further defence lines. If frequency keeps dropping below the statutory limts indicating a large power deficit, automatic *under-frequency load shedding* is activated to disconnect demand and restore power balance. In GB, this is referred to Low Frequency Demand Disconnection (LFDD) and is activated in blocks as indicated in Table 2. LFDD is first activated when frequency drops to 48.8 Hz when 5% of demand in NGET area (England and Wales) is supposed to be disconnected. The percentage is based on the annual peak demand so the actual load shed at any other season may generally be different as the percentage of the actual demand.

Table 2 - Low Frequency Demand Disconnection (LFDD) blocks in GB (NGET, 2019).

Frequency Hz	%**Demand** disconnection for each **Network Operator** in **Transmission Area**		
	NGET	SPT	SHETL
48.8	5		
48.75	5		
48.7	10		
48.6	7.5		
48.5	7.5	10	10
48.4	7.5	10	10
48.3			10
48.2	7.5	10	
48.0	5	10	10
47.8	5		
Total % **Demand**	60	40	40

It is important to appreciate that load shedding is pre-planned and executed by DNOs by opening circuit breakers at 33 kV level and therefore disconnecting indiscriminately all the customers connected to the disconnected feeders. This may also include embedded generation hence weakening the effectiveness of load shedding, as indeed happened on 9 August.

Certain sites which are deemed to be of “major” or “national importance” may apply for Protected Site status and be exempted from load shedding but only if the site does not have, and has demonstrated that it is not possible to install, standby generation. It also must be connected to a discrete feeder so that it can be disconnected separately (DBEIS, 2019a).

3 DESCRIPTION OF EVENTS

Prior to the initial fault, there was approximately 32GW of transmission-connected generation capacity available on the system. Over 30% of this capacity was being provided by wind generation, and 50% was being provided by conventional units. The overall demand was forecast to reach 29GW, which was similar to the outturn demand experienced on the previous Friday. Generation margins for the day were comfortable.

Weather conditions on the day were also not unusual, with a number of yellow warnings of high winds and lightning strike alerts issued by the Met Office.

3.1 First Stage (45 secs): lightning strike, infeed losses and frequency response

At 16:52:33 there was a lightning strike on the Eaton Socon – Wymondley 400kV line –see Figure 4. A lightning strike is nothing unusual, and the protection systems on the transmission system operated correctly to clear it. A lightning strike is effectively a short-circuit causing the voltage to drop, as shown in Figure 5. The associated voltage disturbance was in line with what was expected and should not have caused any significant disturbances. However, the lightning strike on 9 August caused three types of infeed losses discussed in detail below: about 150 MW of embedded generation lost on Vector Shift protection, deloading of 737 MW at Hornsea off-shore wind farm and a loss of 244 MW steam turbine at Little Barford gas-fired power station. While the first loss was to be expected, the two power station losses were unexpected. The total infeed loss was 1131 MW which was above the level required to be secured by the security standards (1000 MW at the time) and therefore higher than 1022 MW of primary frequency response held.

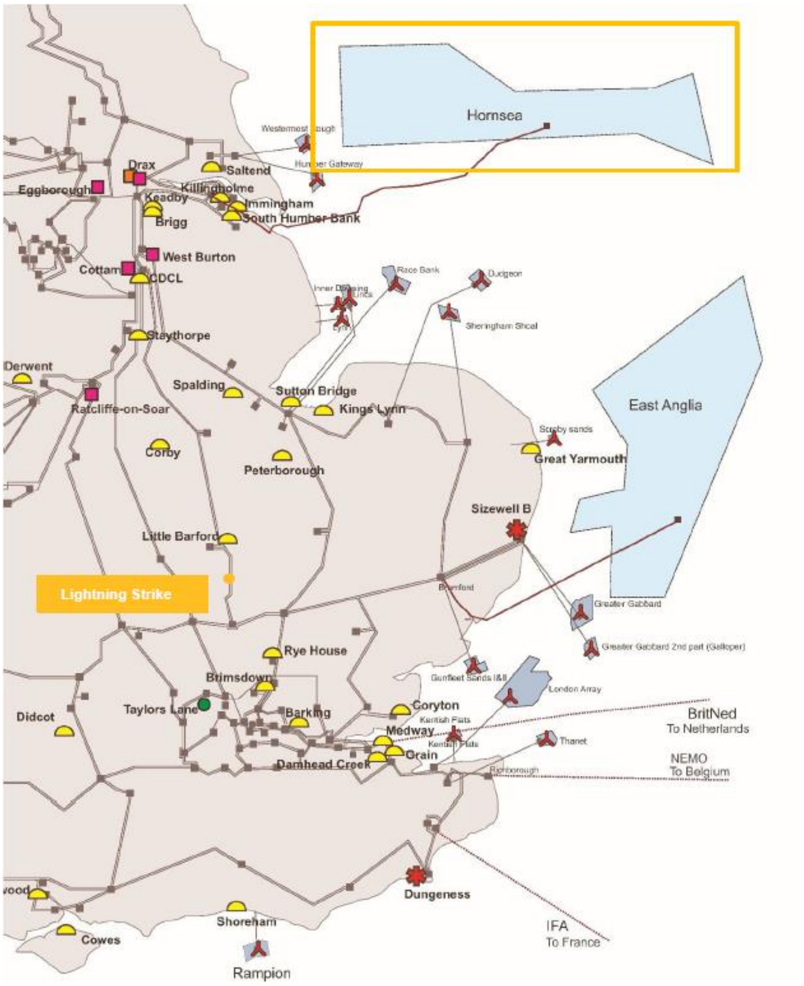

Figure 4 – Map of the affected area (NGESO, 2019b)

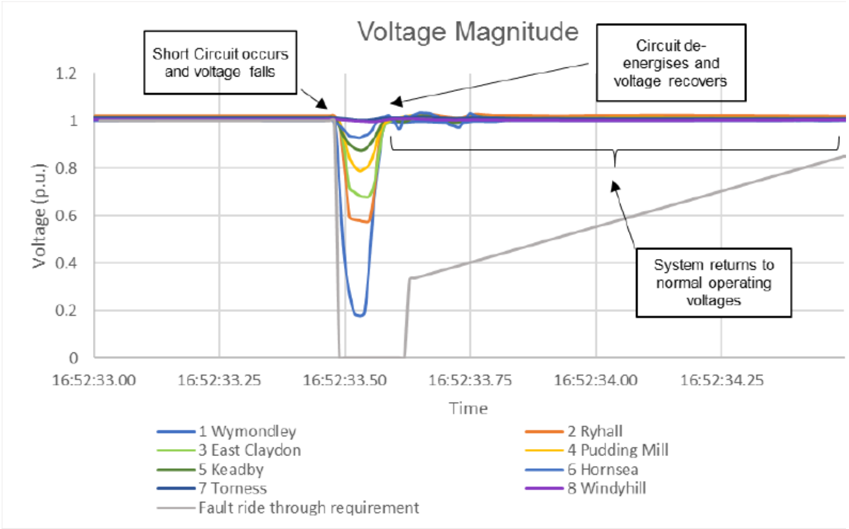

Figure 5 – Single-phase voltage profiles at various locations following the lightning strike (NGESO, 2019b).

Figure 6 shows the resulting frequency drop following such a large infeed loss. Rate of change of frequency was higher than the limit of 0.125 Hz/s, and this caused a further 350 MW embedded generation loss on RoCoF protection. Hence the total embedded generation loss on Loss of Mains protection was about 500 MW making the total infeed loss equal to about 1480 MW, i.e. nearly 50% more than the maximum secured infeed loss. The resulting fall in frequency has released two counter-actions: the primary frequency response (see section 3.1.4 below) that released about 850 MW, i.e. about 83% of 1022 MW reserve held (Ofgem 2020), and the demand frequency response that reduces electrical demand of rotating machinery. (NGESO, 2019a) states that the reduction in demand due to falling frequency is approximately about 350 MW at 49.5 Hz. In the first phase, the frequency dropped to 49.1 Hz, so the demand frequency response can be approximated as about 630 MW. Hence the total combined effect of the primary and the demand frequency response was about 1480 MW which is approximately equal to the total infeed loss[9]. Consequently, the frequency fall was arrested at 16:52:58 and started to recover. Hence, if it was not for further infeed losses, the system could have possibly withstood such a severe disturbance.

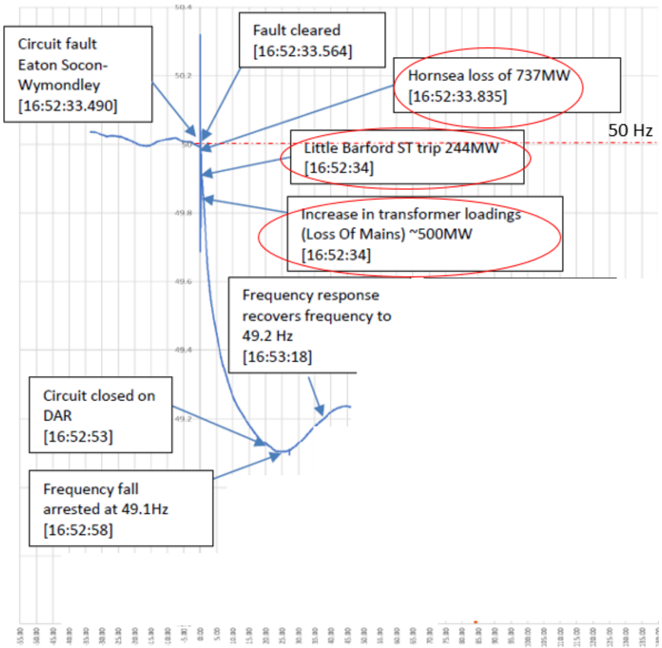

Figure 6 – Frequency trace at the first 45 seconds after the lightning strike (NGESO, 2019b).

[9] The author would like to thank Dr. Callum MacIver of Strathclyde University for his help in explaining the demand frequency response.

3.1.1 *Deloading of Hornsea off-shore wind farm*

Hornsea off-shore wind farm is owned by Orsted and was connected to the grid in February 2019. At the time of the outage, it was progressing through the Grid Compliance process and had fulfilled the necessary requirements to export on an interim basis only. Shutting down of two units generating 737 MW was triggered by a voltage drop following the lightning strike, see the light blue trace in Figure 5, and was caused by discrepancies between its on-shore control systems and individual wind turbines. Orsted identified this stability issue with its voltage control systems about 10 mins before the deloading but at that time, it did not cause any problems.

There were more problems with Hornsea which came to light after the incident. It transpired that there were performance issues with voltage control when the plant operated at full capacity of 1200 MW but the issue was not communicated to ESO. A software update to mitigate the problem was scheduled for 13 August but was implemented on 10 August following the event.

3.1.2 *Loss of steam turbine at Little Barford combined-cycle gas turbine power station*

Little Barford power station is owned by RWE Generation, and it was commissioned in 1995 and went through a major upgrade in 2011/12. One second after the lightning strike, the steam turbine tripped because of a discrepancy in the three independent speed sensors on the turbine. This discrepancy exceeded the tolerance of the control system, causing the generator to automatically shut down. The root cause of the discrepancy in the speed sensors has not been established.

3.1.3 *Embedded generation losses on Loss of Mains protection*

The lightning strike caused sudden voltage changes which were interpreted as islanding by Vector Shift protection. A fast drop in frequency exceeding 0.125 Hz/s was also interpreted as islanding by RoCoF protection on some of the units. The problems of the sensitivity of Loss of Mans protection are well known and documented. There is an on-going Accelerated Loss of Mains Change Programme which addresses the issue but it is due to conclude in 2022. Ofgem recommended reviewing the timescales for the delivery of the programme and consider widening its scope to include distributed generation that unexpectedly disconnected or deloaded on 9 August

3.1.4 *Frequency response*

Table 3 shows the validated frequency response performance (NGESO, 2019b). (NGESO, 2019b) stated that while the overall performance was broadly in line with expectations, there was also some under-performance identified.

(Ofgem, 2020) provided a harsher assessment of the performance of frequency reserve performance stating that it was inadequate. Primary response providers under-delivered by 17% (i.e. more than 11 % indicated in Table 3) and secondary response providers under-delivered by 14% (vs. 12% indicated in Table 3). Mandatory response providers and commercial Fast Frequency Response providers of dynamic primary response (required to provide a continuous, proportional response to the change in frequency) performed particularly poorly, under-delivering by approximately 25% respectively. Some of the reserve and frequency responses could not deliver as they were disconnected by LFDD – see discussion in section 5.1.

Table 3 – Validated frequency response performance (NGESO, 2019b)

Service	**Provider type**	**% validated low frequency response delivered at 30 seconds versus Total MW response held**	
		Validated Primary response	**Validated Secondary response**
Dynamic – Generation (Mandatory response)	BM	103% of 284 MW	102% 325 MW
Dynamic – Firm Frequency Response	BM & Non-BM	74% of 259 MW	81% of 270 MW
Dynamic – Enhanced Frequency Response	BM & Non-BM	94% of 227 MW	94% of 227 MW
Static – Firm Frequency Response	Non-BM	0% of 21 MW	67% of 261 MW
Static – Low Frequency Response through auction	Non-BM	71% of 31 MW	71% of 31 MW
Static - Interconnectors	BM	100% of 200 MW	100% of 200 MW
Total		**89%**	**88%**

3.2 Second stage: next 11 seconds further infeed losses

As discussed earlier, the primary and demand frequency responses released by the falling frequency have covered the initial infeed losses, so that frequency fall was arrested and started to recover. However, there were further infeed losses: 210 MW due to a trip of one gas turbine unit at Little Barford and 200 MW of embedded generation when frequency dropped below 49 Hz. Consequently, frequency started to fall again, as shown in Figure 7 until it reached 48.8 Hz triggering the first stage of load shedding (LFDD).

3.2.1 Loss of first gas turbine at Little Barford

When the steam turbine tripped in the first stage of the event, steam pressure started to rise, and the normal course of action would have been to feed steam directly into the condenser in a steam bypass mode of operation. For reasons presently unknown, this did not work, and steam pressure continued to rise until after approximately 1 minute the first (GT1a) gas turbine tripped with a loss of further 210 MW.

3.2.2 Embedded generation losses when frequency dropped below 49 Hz

When wind turbines started to be connected to the power system in large numbers in the early 2000s, they were usually equipped with relays that tripped them when frequency dropped to 49 Hz. The reason was that with low penetration of wind turbines, their role in power balancing was limited and DNOs wanted embedded wind generators to disconnect from the system in case of any large disturbances for operational and safety reasons. However with large penetration of wind, the picture has changed, and this is was recognised as one of the contributing factors to GB power outage in May 2008, see section 6.1, and also to 2006 Europe-wide disturbance. Consequently, changes were made to Distribution Code in August 2010 reducing the under-frequency protection level to 47 Hz for distributed generators with capacities larger than 5 MW. Hence it is likely that protection settings on some generators were not changed in line with the new regulations and they tripped when frequency reached 49 Hz.

Another possible reason for the embedded generation losses may have been due to internal control systems that cause these generators to deload in response to frequency drops. Some power electronic interfaced generators may have settings within their internal systems which have been configured by the manufacturer, and as a result, are hidden from the DNO or generators themselves. These settings could also explain the loss of further distributed generators when the system frequency dropped below 49 Hz (Ofgem, 2020).

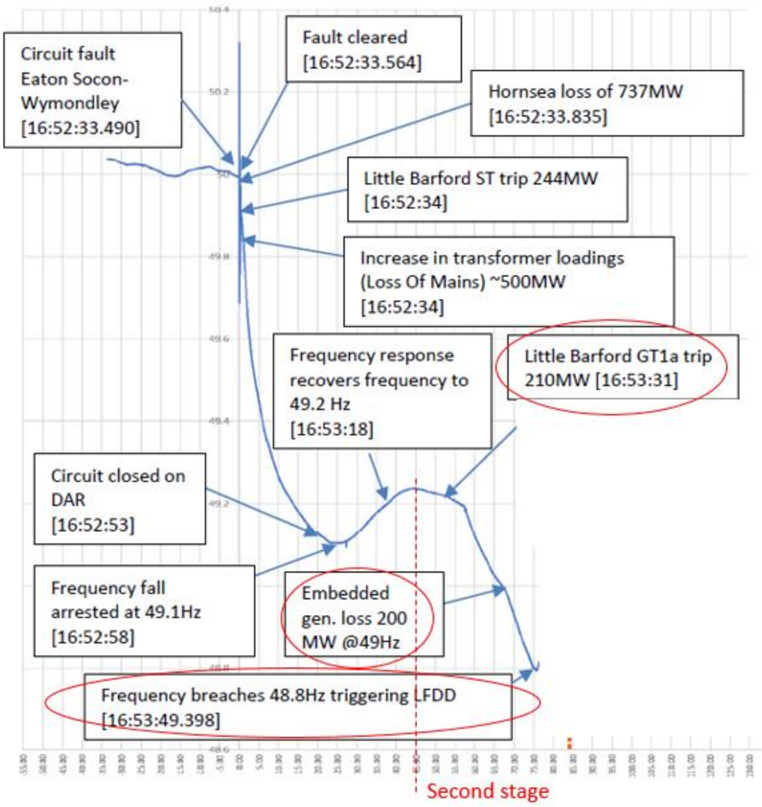

Figure 7 – Frequency trace: the second stage - next 11 seconds (NGESO, 2019).

3.3 Third stage: load shedding and restoration of 50 Hz

When frequency dropped to 48.8 Hz, automatic load shedding (LFDD) was activated, and frequency started to recover quickly – see Figure 8. In total 931 MW of demand was disconnected in England and Wales[10], i.e. 3.2% of the total[11], affecting about 1.1 million people. The power balance deteriorated again when the second gas turbine unit (GT1b) was tripped manually after 30 seconds by staff at Little Barford power plant due to continuing build-up of steam pressure, losing a further 187 MW, but this did not affect the events materially. After a small dip due to the loss GT1b, frequency continued to recover as the control room instructed generators to increase generation and stabilise the system. In total, about 1240 MW of additional power was delivered (on top of about 1000 MW of frequency response), and 50 Hz was restored nearly 5 minutes after the lightning strike. The ESO started to instruct DNOs to restore supply to their customers. Full supply was restored within about 40 minutes

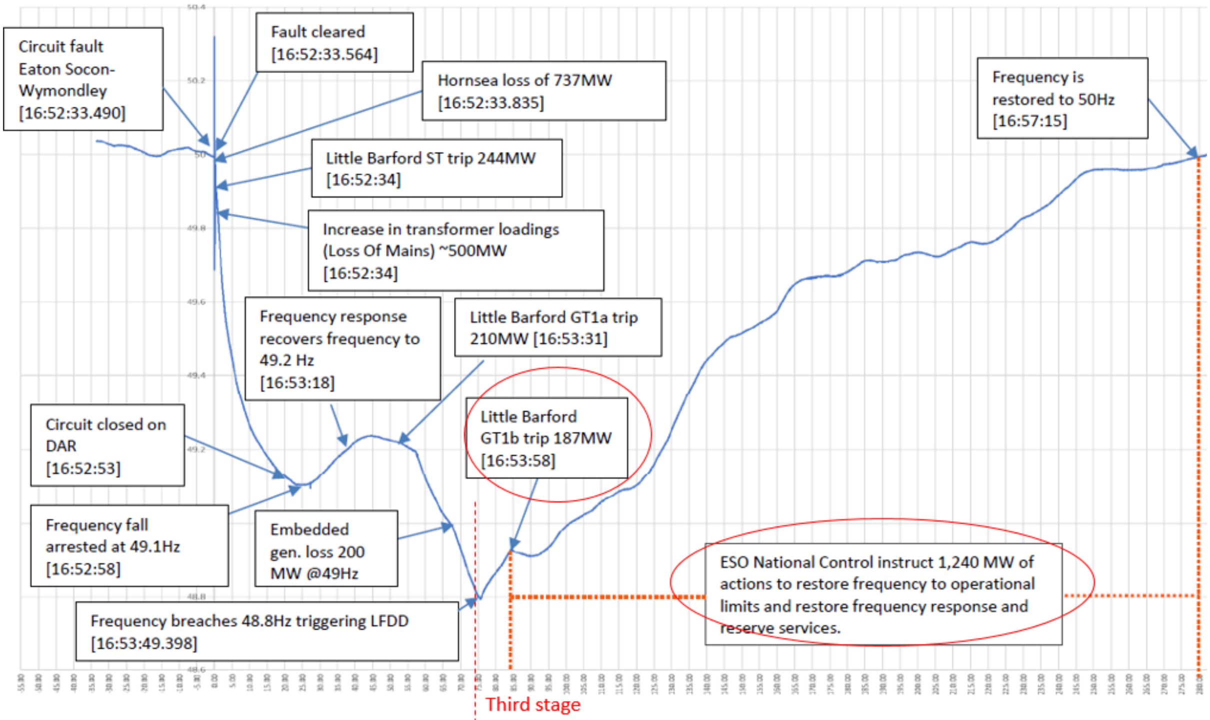

Figure 8 – Frequency trace: third stage - load shedding and restoration of 50 Hz (NGESO, 2019)

3.3.1 Performance of load shedding

The first stage of LFDD should have resulted in disconnecting the equivalent of 5% of winter peak demand. However, in fact, DNOs disconnected only 3.2 % of demand prior to the disturbance - see Table 1. This has not adversely affected the frequency recovery; however, it is a cause of concern.

There are several explanations provided for the lower levels of demand disconnection. The principal cause appears to be the technical specification of some LFDD relays which prevented them from activating. These relays would have activated if the frequency had dropped marginally lower and the Grid Code permits this margin of error. Another cause may have been the disconnection of significant volumes of distributed generation as part of the LFDD operation which lowered the net demand reduction. Currently, it is not possible to discriminate between sites affected by load shedding on the same feeder – both demand and generation is disconnected. The lower bound for the total estimated distributed generation lost across the event is 1,300MW, and the loss could be as high as 1,500MW (Ofgem, 2020), i.e. even higher than the transmission connected generation lost during the event. As more and more generation is connected at the distribution level, the current practice of non-discriminative load shedding is becoming increasingly unsustainable. More generally, there is an increasing need for ESO and DNOs to monitor and understand the role of distributed generation in the energy mix and the control of the electricity system – see section 5.

[10] SP Distribution disconnected 22 MW in Scotland, due to incorrect settings in LFDD equipment, and reconnected the customers without informing the ESO.

[11] (Ofgem, 2020) report states that the amount of load shed amounted to about 4% of the demand.

Table 4 – DNO customers affected by LFDD relays (ESO, 2019b)

Reporting DNO		MW of disconnected demand by LFDD	Customers Affected	Final Restoration Time of Demand
Scottish Hydro Electric Power Distribution (SHEPD)		0		
Scottish Power (SP)		22	23,117	16:59
Northern Power Grid (NPG)	North East	76	93,081	17:18
	Yorkshire	14	10,571	17:12
Electricity North Limited (ENW)		52	56,613	17:17
SP Manweb		130	74,938	17:15
Western Power Distribution (WPD)	East Midlands	122	150,445	17:25
	West Midlands	160	187,427	17:37
	South Wales	36	29,060	17:11
	South West		110,273	17:22
UK Power Networks (UKPN)	Eastern	69	79,390	16:56
	London	174	239,861	17:37
	Southern	69	81,358	17:15
Scottish Electric Power Distribution (SEPD)		7	16,744	17:07
Totals		**931**	**1,152,878**	**17:37**

4 IMPACT ON OTHER CRITICAL INFRASTRUCTURES

The main direct impact of the event was that about 1.1 million customers lost supply for up to 40 minutes. However, it was the serious impact of the disturbance on other infrastructures and services, rather than the power loss itself, which made the outage headline news.

4.1 Rail

There is some discrepancy between the reports regarding whether or not traction supplies were affected by LFDD. (NGESO, 2019b) states: “the DNOs confirmed that no track supplies were lost due to the DNO’s LFDD protection operation” while (Ofgem, 2020) states that “the traction supplies to the Wirral line on Merseyrail were disconnected as a result of SP Energy Networks’ LFDD operations. Three Transport for London stations and eight signalling sites at rural locations across England and Wales were also thought to have been affected by LFDD operations, although traction supplies were unaffected”. However, that discrepancy in reporting is not that important as all the reports agree that the main effect on rail services was due to the wide frequency excursions. Most importantly, a certain class of trains (Desiro City Class 700 and 717 manufactured by Siemens and operated by Govia Thameslink Railway (GTR)) suffered a protective shutdown when frequency reached 49 Hz. GTR maintains that the technical specifications for the trains stipulated that they should have operated for a short time when supply frequency drops down to 48.5 Hz, but subsequent investigation discovered that it was not followed. To make things worse, out of 60 trains affected only about half could be restarted by the drivers. The remaining half, which had new software installed, had to wait for a technician to arrive with a laptop to restart it manually, which introduced significant delays.

The impact on the rail network was severe: there were 23 train evacuations, and thousands of passengers had their journeys delayed with 371 trains cancelled, 220 part cancelled, and 873 trains delayed. London St Pancras and King’s Cross stations had to close for several hours due to overcrowding, and London Euston went exit only for a period of time. It all happened on Friday around 5 pm, i.e. at the worst possible time, and it was this rail chaos that was the main source of public anger and made news headlines.

London Underground have confirmed there were impacts on the London Underground Victoria Line, which was suspended as a result of the event and service was restored at 17:35hrs. UKPN have confirmed that LFDD did not impact the Victoria line, but they had an internal traction issue.

4.2 Health

Two hospitals were affected by LFDD with their back-up generation working as designed. Another hospital was affected by the fall in frequency/voltage excursion, despite not being disconnected as part of LFDD. This was due to incorrect protection settings on the hospital's own network, which resulted in the site switching over to back-up generation and one of its 11 generators failing to operate.

4.3 Water

Approximately 3,000 people experienced water supply disruptions due to booster water pumping stations failing to automatically switch over to back-up power supplies. Some of these customers would have experienced a temporary loss of running water in their homes, but others would have remained unaffected due to water storage in the system, allowing running water to continue. The majority of customers were restored within 30 minutes.

4.4 Other Energy

An oil refinery was disconnected as a result of the site's system, which detected a drop in frequency and disconnected the plant to protect on-site equipment. The refinery operations team utilised the site's emergency procedures and automated systems to safely shut down portions of the plant, however, due to the complexity of restarting large process units it took a few weeks to restore normal operations.

4.5 Airports

Newcastle Airport has lost supplies for 17 minutes. However, the back-up supplies for safety-critical systems operated smoothly to, and there were no serious consequences.

There was also another unnamed airport affected in Midlands (E3C, 2020). While it was unaffected directly by LFDD, it switched to-back up power supplies without issue and was restored within a few minutes. A fault with its on site internal network meant that power to some services was delayed for up to 50 minutes.

5 WHAT DOES THE OUTAGE TELL US ABOUT THE STATE OF GB POWER SYSTEM?

Power outages are like stress tests exposing strengths and weaknesses of the power system as the whole and its constituent elements and other critical infrastructures connected to it, so it is important to consider what does the power outage tell us about the state of GB power system.

On the face of it, everything was fine as the power system responded exactly how it was designed to. The system is designed to withstand a (N-1) event but the outage was caused by simultaneous failures of two power stations. Hence the infeed loss was higher than the secured one, and the frequency dropped below the statutory limits to 48.8 Hz, which triggered load shedding (LFDD). Despite the amount of load shed being less than designed, and further infeed losses totalling nearly 1900 MW, the frequency was returned to 50 Hz in nearly 5 mins and power supplies restored within 40 mins. Consequently, Ofgem gave the ESO a clean bill of health. Ofgem was less happy with the owners of the two power stations which failed and two of the DNOs who were in a technical breach of their requirements[12]. They were not fined but agreed to pay voluntary payments to Energy Industry Voluntary Redress Scheme: Hornsea1 Ltd and RWE Generation UK plc paid £4.5M each while Eastern Power Networks and South Eastern Power Networks paid £1.5M each.

Should we then be happy about the state of the GB power system? The answer is: not really. The blackout has uncovered important fault lines which may significantly affect the reliability of the system in the near future.

5.1 Does (N-1) reliability rule need to be reviewed?

While the system reacted according to the book, i.e. SQSS, the question is if the book is still adequate to the needs. This was recognised by (Ofgem, 2020) which recommended examining if SQSS is fit for purpose with respect to the impact of DG, requirements for holding reserve, response and system inertia. In particular, they recommend assessing whether it is appropriate to provide flexibility in requirements for securing risks events with a very low likelihood, and costs and benefits of requiring availability of additional reserves to secure against the risk of simultaneous loss events. In this section we will look in particular at the latter point, i.e. we will examine whether or not the well-established and universally accepted (N-1) reliability rule should be revised. As the last serious (N-2) incident in GB happened in May 2008 (see section 6.1), perhaps the (N-1) principle still holds as one outage per 11 years is quite reasonable from the reliability point of view?

[12] The two DNOs reconnected demand without instruction from the ESO

To answer that question, it is important to realise that the (N-1) standard is a common-sense engineering principle that was accepted decades ago when the power supply industry had the following main technical characteristics:

- The main sources of generation were synchronous generators that provided inertia necessary to contain any frequency excursions.
- Power stations were almost exclusively connected to the transmission system so all generation was directly controllable by SO.
- Power stations were also fully dispatchable as they were fed by fossil fuels, water or nuclear energy.
- Distribution networks were passive and did not contain much DG
- SO had detailed models of all main power system elements: generators, their control systems, the transmission system[13].

Consequently, SO was like an omnipresent and omnipotent god who saw everything and could do almost anything. Of course, the system did evolve, but rather slowly, so SO had time to commission all new equipment properly and consider any interactions. As SO knew the system and its elements very well, it could predict (and eliminate) any common modes of failure and reasonably expect that the probability of two large power stations failing simultaneously and <u>independently</u> was very low.

However, over the past ten years or so the situation has changed quite dramatically in GB and many other countries due to the decarbonisation drive. The main changes were the following:

- There has been a continuous and accelerating replacement of traditional fossil fuel generation by wind and solar. In 2018 renewable generation provided one-third of GB electricity (DBEIS, 2019). Not only wind and solar are not dispatchable but also they do not provide inertia as they are connected to the system by converters.
- In GB, DG is not not visible to the ESO[14] , which means that effectively DG is treated as negative demand by the ESO. This approach is increasingly non-viable as the amount of DG capacity has increased to reach about 1/3 of the total GB generation capacity in 2019 (DUKES, 2019). The amount of DG that tripped on 9 August was of a similar range as the transmission-connected generation, by some estimates even higher. As (Ofgem, 2020) states: "The event showed that while each distributed generator that de-loaded or tripped may have been small, large volumes of embedded generation behaving in unison can have major impacts on the system. Understanding the behaviour of these generators is critically important for managing the risks to consumers of demand disconnection in a cost-effective manner, and this requires detailed knowledge of their operation and design".
- In addition to wind and solar generation, a significant amount of batteries, active demand and generally smart grids technologies have been added on to the system over the last 10 years. Those converter-connected resources are often equipped with proprietary control systems, models of which are not known to SO, and which means that SO cannot model accurately the system response to disturbances. This was exemplified on 9 August when proprietary voltage control systems of Hornsea wind farm malfunctioned. There can be some possible unstable interactions between control systems which SO is not aware of. To put in simple terms, it means that a lot of new gear and controls were added to the system in a very short time and not all of it was adequately stress-tested and their interactions considered. Indeed, Hornsea 1 offshore power station was progressing through the Grid Code compliance process at the time.
- The ESO has a sophisticated system for contracting frequency response from a variety of providers but there are questions about their compliance. On 9 August, the primary response providers under-delivered by 17% and secondary response providers under-delivered by 14% (Ofgem, 2020). Mandatory response providers and commercial Fast Frequency Response providers of dynamic primary response (required to provide a continuous, proportional response to the change in frequency) performed particularly poorly, under-delivering by approximately 25% respectively. The reason for the under-delivery is again the fast pace of change. In the old days, when frequency response was delivered only by transmission-connected traditional plants, it was relatively easy to check their compliance with the Grid Code to make sure that they deliver when needed. Now, with a large number of often small providers, checking their compliance is getting increasingly difficult.
- We can only expect that the rate of power system changes will accelerate given the increasingly aggressive decarbonisation targets around the world. For example, the UK has the goal of net-zero greenhouse gas emissions by 2050.

To summarise the issues outlined above, in the "good old days" SO had to deal with "known unknowns" – they knew the system, they knew what could fail and how. Now we have a lot of "unknown unknowns", i.e. hidden

[13] Admittedly, load modelling has been a perennial problem.
[14] In other countries System Operators have a much better visibility of DG

common modes of failures SO does not know about, as demonstrated by the outage on 9th August. Hence it is no longer reasonable to assume that failures of power stations are independent events and therefore (N-2) event cannot be dismissed as a very rare event. This would suggest that we have two options discussed below.

5.1.1 Option 1: Business As Usual

The first option would be to try to maintain the old world with an omnipresent and omnipotent System Operator. That would require System Operator to have full visibility of all generation in the system, both transmission- and distribution-connected. This could be imagined as a hierarchical structure, with SO managing the transmission level and Distribution System Operators (DSOs) taking over some functions of SO and managing the distribution level. However if the current trend continues, and all the signs are that it will and may even accelerate to achieve the goal of net-zero carbon economy by 2050, the number of small distributed generators is expected to increase making gathering information and controlling increasingly difficult. Modelling all generators, their controls, distributed storage, active demand and other smart grid technologies would be increasingly difficult even if we assume that it would be possible to force all the companies to disclose how their (often proprietary) controls work. We should strive to achieve as much information as reasonably possible but acknowledge that achieving full observability and controllability is probably a thing of the past.

5.1.2 Option 2: Provide additional security margin

The second option is to acknowledge that it is impossible to fully monitor, model and control the whole system at both transmission and distribution levels. That means acknowledging that the probability of common hidden modes of failures has increased and modify security standards to reflect it. While adopting (N-2) criterion might be prohibitively expensive, it might be prudent to consider strengthening the (N-1) rule by providing extra say 10% security margin and let us attempt a cost-benefit analysis of that. Our estimates of costs and benefits will be quite approximate and should be treated as order-of-magnitude comparisons.

There are two main components of costs to maintain (N-1) reliability: frequency reserve and keeping RoCoF below the limit (currently 0.125 Hz/s). NGESO provides regular reports on the cost of ancillary services and here we will use the March 2020 report (NGESO, 2020b). Frequency reserve is considered under the heading Response and in 2019/20 the cost was about £152 million but unfortunately there is no breakdown of the total into the primary, secondary and high frequency response[15]. Volume-wise, the three components take about one-third each. For our approximate analysis let us assume that the costs are also divided one-third each giving a total of about £100 million for the primary and secondary frequency reserve.

The cost of maintaining the RoCoF limit in 2019/20 was quite high: £210 million, i.e. more than double of the primary and secondary frequency control. Hence the total cost of (N-1) security, consisting of the cost of providing frequency reserve and managing RoCoF, was about £310 million.

To estimate the cost of increasing the security margin we would ideally need the price-quantity characteristics of providing frequency reserve and ROCOF. Unfortunately there is no such information in NGESO reports. Comparing data from different months did not provide any consistent information, probably because conditions and providers changed from month to month. Hence let us undertake an approximate analysis by assuming a general shape of the characteristics.

Assuming that the cost characteristics are linear, 10% increase in the reserve would cost extra £31 million/year. However it is likely that the cost-quantity characteristic is non-linear with an increasing slope. Then assuming a quadratic characteristic, 10% increase in reserve would mean doubling the extra cost to about £62 million year. Hence we have arrived at a rough estimate of the cost increase to be between £31 and £62 million/year.

Now let us consider the benefits of an increased reserve by considering the direct cost of the 9 August outage. It is notoriously difficult to estimate the Value of Lost Load (VOLL) so here let us assume a range £10,000-30,000/MWh (DECC, 2014). The outage lasted about 40 mins with 931 MW disconnected at the peak giving about 620 MWh of energy lost and therefore the cost in the range £6-18 million. Incidentally, the outage cost calculated using the often-used VOLL=£17,000/MWh is exactly equal to the "voluntary" payments of energy companies (£10.5 million)– we do not know whether or not it was accidental.

One should consider also the cost of failing trains as it was an unexpected cost and therefore not covered by VOLL. UK rail regulations stipulate that a passenger is allowed to the full refund of the ticket if a train is delayed more than 1 hour. The outage happened at evening peak (around 5m on Friday) and most affected were rail services around London. According to (DfT, 2019), two-third of all rail journeys in the UK start or terminate in London, with about 750,000 passengers arriving on average by 9 am and about 170,000 passengers arriving after 5 pm. Of course not all the passengers who arrive by 9 am leave after 5 pm but it is reasonable to expect that a

[15] High frequency response covers actions to reduce frequency when it is going above the statutory limits.

majority will do so for the following reasons: (a) tickets for journeys which finish by 9 am are very expensive with no discounts available so usually a majority of people arriving by 9 am are commuters and business travellers who leave in the evening; (ii) tourists usually arrive after 9 am as they have to travel from other locations. Also, as the disruption happened on Friday evening, it was not only the day commuters, but also week commuters and Londoners going for a weekend retreat, who would leave in the evening. Hence, for our approximate analysis, let us assume that the down factors counterbalance the up factors so the total number of passengers affected was about 920,000. According to (ORR, 2020), the average revenue per rail passenger in 2019 in the UK was £5.59. Multiplying the number of passengers affected (920,000) by £5.59 gives the total cost of about £5 million. This is likely to be a substantial underestimate, as generally tickets from/to London are more expensive than in the rest of the country and the peak-time tickets are especially expensive with no discounts for forward booking. So on the one hand we may have overestimated the number of people affected, but on the other hand, we have underestimated the average ticket price. Hence the error bounds for the cost estimate are quite large so assuming 50% error, the direct cost of tickets was in the range £3-8 million.

Adding the outage cost from VOLL (£6-18 million) gives the total direct cost of the outage in the range of £9-26 million. This estimate does not include other knock-on costs discussed in Section 4, especially the oil refinery and chemicals manufacturing plants being disconnected for several weeks and therefore likely suffering multi-million losses. It also does not include the knock-on financial effects of train delays or compensation for pain and misery of the travellers. Nevertheless, a comparison with the cost of providing extra 10% of frequency reserve (£31-£62 million/year) leads to a conclusion that the cost of extra security is likely to be higher than the benefit, even assuming that outages happen every year. Hence, the conclusion would appear to be that, at least in GB, the approximate cost-benefit analysis does not currently support increasing the (N-1) security margin even by as little as 10%.

5.1.3 How to reduce the cost of providing security?

It should be emphasised that the above conclusion was based on the static and backwards-looking analysis. There are multiple factors suggesting that the balance of costs and benefits will change in the future. As discussed earlier, it is expected that the frequency of outages may increase due to fast changes happening to the electricity supply industry. RoCoF costs are likely to go significantly down when the current RoCoF limit is increased from 0.125 Hz/s to 1 Hz/s. VOLL is expected to increase due to increased electrification of transport and heating necessary to reach the UK's net-zero emissions target. And finally and most importantly, the cost of providing the security margin is expected to come down due to introduction of innovative frequency controls that use non-traditional providers. As shown in the previous section, maintaining the RoCoF limit in GB is quite expensive (£210 million/year) as it is usually done by reducing the imports via DC interconnectors and dispatching instead expensive traditional generation. Wider use of the innovative frequency controls discussed below should significantly reduce the costs.

There are many trials around the world of innovative frequency controls, supplementing the traditional frequency control provided by generators. They essentially consist of inserting energy from a converter-connected energy source (e.g. wind turbine, battery, HVDC interconnector, PV not operating at full capacity, supercapacitor) in response to a frequency drop. An alternative to increasing generation is to reduce temporarily demand using devices such as fridges, air-conditioners, heaters etc. and in such a way that the service the devices provide is not affected (Trovato, 2018). The converters can modulate the energy inserted (or withdrawn) according to a pre-specified characteristic. When the amount of energy inserted (or demand reduced) is proportional to the time derivative of frequency df/dt, the control emulates the inertial effect and therefore is often referred to as the "synthetic (or virtual) inertia". It will have the effect of reducing the initial RoCoF and frequency nadir. On the other hand, if the energy inserted is proportional to the frequency deviation Δf, it emulates the droop control of traditional turbines so it reduces the steady-state frequency drop and te nadir (see Figure 2). A dynamic combination of the inertial (df/dt) and droop (Δf) control can reduce both RoCoF and steady-state frequency drop while eliminating the nadir and minimising the control effort (Mallada, 2016).

It should be emphasised that the "virtual inertia" is not a perfect replacement for the physical inertia. While physical inertia releases kinetic energy automatically, according to the laws of physics, the release of energy by "virtual inertia" suffers from inevitable delays because the control system has to detect and process the frequency signal before reacting to it. It is important to appreciate that frequency cannot be measured directly but only deduced from measurements of AC voltage or current. Mathematically, frequency f is the derivative of the measured voltage angle. Hence, df/dt is the second derivative of the underlying physical quantity which one can measure and therefore it is a very noisy signal.

Measuring df/dt takes 2-3 electrical cycles which for 50 Hz system means 40-60 ms. The signal is quite noisy so it has to be processed, which takes about 20 ms. Then the energy source behind the converter has to be activated and the delay depends on the technology used. It takes at least 4 ms for a flywheel, 10-20 ms for batteries or supercapacitors, 40-500 ms for a wind turbine, 100-200 ms for solar PV and 50-500 ms for HVDC (GE, 2017). Hence, the total delay between the disturbance and activation of "virtual inertia" can be somewhere between 0.1 s and 0.5 s. Currently such delay is acceptable for most systems as they still have a considerable amount of physical inertia installed which limits the initial RoCoF. However, in some systems with a high penetration of wind/solar (like e.g. South Australia), the RoCoF following a large infeed loss may reach about 5 Hz/s, so 0.1-0.5 s delay would mean a drop of frequency of 0.5-2.5 Hz before "virtual inertia" is activated. This may have serious consequences for frequency stability as the delayed release of "virtual inertia" will result in a deep frequency nadir which may inadvertently activate under-frequency load shedding. Hence "virtual inertia" cannot replace physical inertia completely and maintaining some physical inertia on the system may be necessary. It could be done by e.g. keeping the generators of decommissioned traditional plants connected to the system so that they still provide physical inertia[16]. Some countries consider introducing "inertia markets" that would provide a level-playing field for different providers (Poolla, 2020). However currently utilities tend to prefer including the provision of inertia and innovative frequency controls in the existing ancillary services markets (AEMC, 2018), (NGESO, 2020a). As more services are added, and more providers enter, the costs are expected to come down.

It should be noted that there is a new technology of so-called *grid-forming converters* which do not rely on the physical inertia of rotating masses to keep power system balance and therefore do not require measuring frequency with associated delays (Paolone, 2020). Wider application of those new techniques may lead in future to inertia-less systems. This however would require a fundamental change of paradigm of the current power system operation and control which we will not discuss here.

An alternative to providing system security by maintaining a passive (and expensive) security reserve is to rely on emergency controls, referred to as Special Protection Systems (SPS) or Remedial Action Schemes (RAS), that react to specific contingencies (ENTSOE, 2012). There are many RAS proposed in the literature and it is not the aim of this paper to discuss them. One example is early activation of under-frequency load shedding based on the RoCoF signal, rather than frequency drop (Banijamali, 2019). As the size of the infeed loss ΔP can be estimated from RoCoF (knowing system inertia H – see equation (1)), load shedding can be made more accurate and smaller.

Innovative frequency controls have been around for some time however we believe that a major impediment to their wider application is not technical but institutional. SOs tend to be conservative and prefer maintaining a large security margin and physical inertia which, while more expensive, is regarded to be more reliable than controls which might malfunction or function when not needed. Nevertheless, the increased probability of outages, combined with a high cost of increasing the security margin and maintaining physical inertia, could force SOs to consider innovative frequency controls more widely.

5.2 Load shedding

The outage has demonstrated that the effectiveness of load shedding in reducing the overall demand could be much lower than expected due to indiscriminate shedding of all customers on the disconnected feeders, including embedded generation. As the amount of embedded generation is very likely to increase in the coming years, we believe it is highly desirable to consider how to make load shedding more flexible and selective. With rapid advances in telecommunication, it should be possible to assess in real-time the actual loading on individual feeders so that load shedding has the maximum possible effect. Maybe it could also be feasible and cost-effective to implement load shedding at 11 kV level, rather than 33 kV as presently, hence allowing more selective operation (Bell, 2019)?

5.3 Microgrids

Another related issue is the question if it would be possible to maintain supply to the customers in a part of the network disconnected by load shedding. After all, there may be embedded generators connected which could continue to generate and supply at least some of the customers disconnected by load shedding but currently are required to disconnect to prevent operation and safety-related problems. In other words, that disconnected part of the network would form a microgrid that would operate separately from the main transmission network and rely on the supply from embedded generators. There is a large literature devoted to microgrids that discusses a variety of technical, economic and regulatory challenges. However, it should be noted that microgrids only make sense if there is a significant probability that a disturbance will cause islanding of a part of the network and that the disruption will last significant time. This may be caused by a weak connection of a microgrid to the main network and therefore a significant probability of long-lasting disconnection - see, e.g. the island of Bornholm or Greek islands. Another example could be the areas that are regularly hit by natural disasters such as hurricanes or earthquakes. However, the GB grid enjoys (so far) very high reliability and the probability of load shedding, or

[16] Such generators are referred to as *synchronous condensers* as traditionally they have been used for reactive power compensation, i.e. voltage control.

generally islanding, is rather low- only two load shedding events in the last few decades. Even if a part of the distribution network is disconnected, usually supply returns rather quickly. Hence the very significant effort and cost to overcome technical and regulatory challenges of creating a microgrid might not justify the benefits of avoiding very occasional and short-term disconnections. The situation may change in the future with increased penetration of embedded generation.

5.4 Interactions between critical infrastructures

As concluded in section 6.3, outages really matter only if they cause a significant disturbance to people, i.e. they are either of long-duration or affect critical infrastructure like transport at rush hour. Hence it is of vital importance to ensure that critical infrastructures can ride through disturbance in the power network. This is especially important as, see section 5.1, the probability of disturbance in the power network is increasing due to the addition of a very significant amount of new equipment and controls on the network. Not only back-up supplies have to be regularly checked but also compliance with the regulations must be enforced to make sure that the infrastructures can survive large frequency deviations.

6 DO OUTAGES MATTER?

The question posed in the title of this section may seem to be rather rhetorical with the obvious answer: yes. It is obvious and hardly needs repeating that a secure supply of electricity is of fundamental importance for a modern society and economy. Without it, life as we know stops. All the major blackouts throughout the worlds have been major disturbances causing significant economic losses, and sparking wide media coverage and heated discussions about who to blame. However, the evidence from GB outages over the last two decades would suggest that in this country at least, this has not always been the case and in this section, we will analyse this phenomenon by considering the previous transmission-level outages.

6.1 May 2008 outage

The GB outage that happened in May 2008 (National Grid 2009) was quite similar to the one on 9th August 2019. Yet it did not result in a wide media coverage so it is worth considering it in detail.

On the morning of 27th May 2008 two large power stations tripped within two minutes independently of each other: 345 MW Longannet coal power station in Scotland (Generator A) and 1237 MW nuclear power plant Sizewell B (Generator B). The annotated frequency trace is shown in Figure 9. The total loss was 1582 MW which was more than the maximum secured infeed loss of 1260 MW. Similarly, as on 9th August, the frequency dropped rapidly causing loss of some embedded generation so that the total infeed loss was 1714 MW. Fast frequency reserve was activated that managed to restore the power balance and stop the frequency drop at 49.15 Hz. Then frequency started to recover but, similarly as n 9 August 2019, there were further infeed losses due to 279 MW of embedded wind farms tripping, and frequency started to fall further-reaching 48.8Hz and activating load shedding[17]. 546 MW of demand was shed affecting approximately 550,000 customers, i.e. about half of the affected by 9th August event. The supply was restored within 20-40 minutes. Despite such a similarity to 9th August event, the May 2008 outage did not generate headlines or much media interest.

[17] At that time load shedding was referred to National Low Frequency Demand Disconnection Scheme.

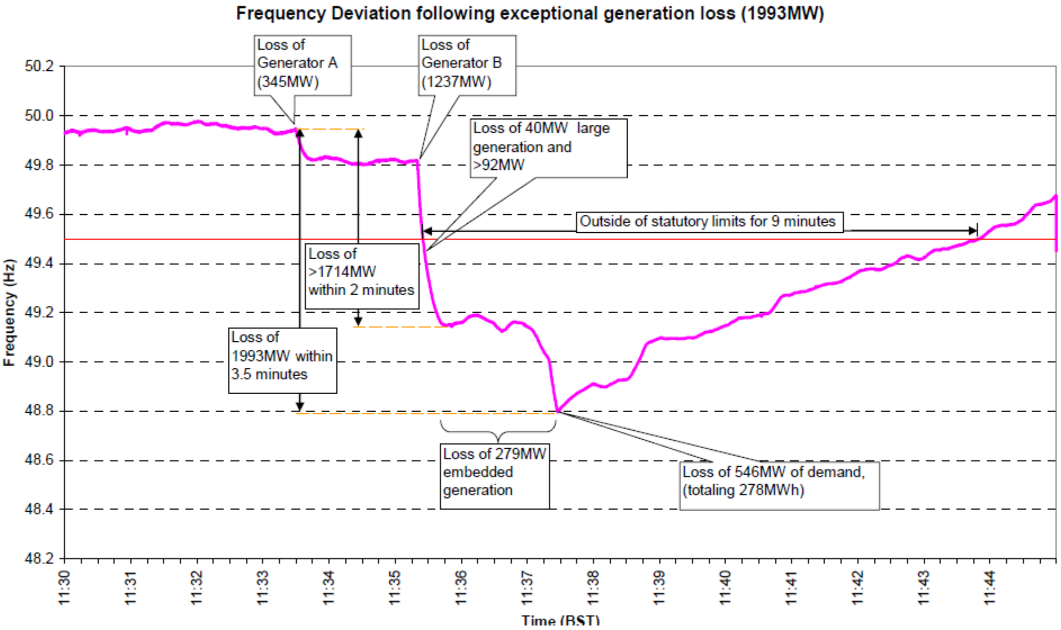

Figure 9 – Frequency trace of May 2008 outage (National Grid, 2009).

6.2 Outages in 2003

It is also interesting to look at other outages which occurred in England in 2003. In the early evening of 28 August 2003, electricity supplies to 476,000 consumers in South London were interrupted (Ofgem, 2003). Just over a week later, electricity supplies to 220,000 consumers to the East of Birmingham were also interrupted (Ofgem, 2003). In both of these events, power supplies were restored to all customers within an hour. In both cases the loss of supply arose from the incorrect operation of protection equipment.

However, while both outages were quite similar in terms of the causes and the effect on the power system and its customers, the knock-on effects on other infrastructures were different. The London outage significantly disrupted London Underground and the rail system around London at peak time, causing a very significant public outrage and attracting widespread media attention – similarly as the 9 August event. The Birmingham outage also affected a number of major consumers including Network Rail, Birmingham International Airport, the National Exhibition Centre (NEC), two major car plants, Solihull and Sutton Coldfield town centres, shopping centres and a hospital but it did not attract a large national media coverage.

There was also a third transmission outage in 2003 in the Cheltenham and Gloucester area on 22 October when 165 MW was lost and about 100,000 people affected (Ofgem, 2004) but it was almost completely ignored not only by the media but also the industry – no comprehensive report was published.

6.3 When do outages matter?

Hence a question arises, based on the evidence of five large-scale transmission-level outages affecting hundreds of thousands of customers over the last two decades, why some outages attract public attention and others do not. To understand that, let us look at the similarities and differences between them. The two outages that did attract a large media and public attention were the 9th August 2019 and 28th August 2003 events that caused a large disruption to transport services around London. The 2003 Birmingham outage also affected critical infrastructures including transport, but it was Birmingham, not London. On the other hand, the May 2008 GB-wide load shedding, which was quite similar to the 9 August 2019 event, and the 2003 Cheltenham and Gloucester outage did not affect critical infrastructures. Hence the conclusion seems to be that, in GB at least, outages matter only if they satisfy two conditions: (i) the affect critical infrastructures, especially transport, and (ii) they affect London and the surrounding areas. Unless those two conditions are satisfied, none really cares[18].

Let us now consider why the disconnection of hundreds of thousands of customers, but without affecting critical infrastructures, does not attract public attention as it happened, e.g. during May 2008 event. The main reason seems to be that supply to customers was restored within about half an hour. Outages of that duration happen all the time due to faults at the distribution level due to e.g. a digger hitting a cable, although without affecting that large number of customers. What really matters to the public is not the number of people affected but how a

[18] This may be a biased view of the author who lives in the north of England but the evidence of five outages is quite conclusive

disturbance affects their life. Hence if a disturbance is of a relatively short-duration and does not disrupt significantly critical infrastructures, it does not attract much attention.

It is also useful to compare the GB outages to large blackouts that happened around the world and attracted significant public attention. Those big blackouts tend to happen either due to significant faults on transmission networks which spread quickly or due to natural disasters, like hurricanes, earthquakes or forest fires. GB has a well-designed and maintained transmission network which means that the probability of large transmission faults quickly spreading is low[19]. Also, GB is an island which means it is unlikely to be affected by faults in neighbouring networks, causing cascading failures[20]. Natural disasters are unlikely as GB is blessed with a moderate climate – although some areas may be affected by floods. And finally, there are no forests in GB to speak of so forest fires are not an issue.

7 CONCLUSIONS

The power outage on 9th August 2019 that affected over 1 million customers in England and Wales and caused a major disruption to other critical infrastructures (especially rail services in the South of England including London) was a major news item and sparked wide-spread discussions about who is to blame. Power outages are like stress tests exposing strengths and weaknesses of the power system as the whole and its constituent elements and other critical infrastructures connected to it so our main aim was to consider the title question: what does the power outage tell us about the state of GB power system.

On the face of it, everything was fine as the power system responded exactly how it was designed to. A lightning strike caused two power stations to trip. As the infeed loss was higher than the secured one, the frequency dropped below the statutory limits to 48.8 Hz, which triggered load shedding (LFDD). The frequency was then returned to 50 Hz in about 5 mins, and power supplies were restored within 40 mins. The main adverse effect of the blackout was a severe disruption to rail service around London due to an unexpected failure of trains when frequency dropped to 49 Hz. Consequently, Ofgem gave the ESO a clean bill of health. Should we then be happy about the state of the GB power system? The answer is: not really. The blackout has uncovered important fault lines which may significantly affect the reliability of the system in the near future.

The decarbonisation drive resulted in a significant amount of new equipment and controls added to the system in a very short time. All the new equipment has its own sophisticated control systems with possibly some unknown interactions. Also the system inertia has been significantly reduced. The pace of change is likely to increase due to the adoption of ambitious environmental targets such as net-zero emission by 2050. Hence it will be increasingly difficult for SO to fully monitor, model and control the whole system and therefore the probability of common hidden modes of failures, as the one exposed by the 9 August outage, will be significantly increased. The business-as-usual option is not feasible so it might be prudent to reconsider the old (N-1) security standard by providing an additional reserve. While the approximate cost-benefit analysis has shown that increasing the security reserve is currently too expensive, the balance of costs and benefits is likely to change in future. In particular, the costs can be significantly reduced by introducing a range of innovative frequency controls, including the provision of "virtual inertia" and Remedial Action Schemes. However "virtual inertia" suffers from measurement and processing delays so maintaining some amount of physical inertia, e.g. by using synchronous condensers, may be necessary to limit RoCoF. This may change in future when wider application of grid-forming converters may make it possible to achieve inertia-less systems. One of the main impediments to introducing innovative controls is the attitude of SOs who tend to be conservative and prefer maintaining a large security margin and physical inertia which, while more expensive, are regarded to be more reliable than controls which might malfunction or function when not needed.

There were also other issues highlighted by the outage. Embedded generation reached such a high penetration level that it cannot be treated any longer as negative demand. Its importance for real-time power balancing and in response to disturbances requires a new approach. Traditional under-frequency load shedding disconnects all customers indiscriminately on the disconnected feeders, including embedded generation and frequency response units. With rapid advances in telecommunication, it should be possible to assess in real time the actual loading on individual feeders so that load shedding has the maximum possible effect and perhaps also implement load shedding at 11 kV level, rather than 33 kV, hence allowing more selective operation.

[19] National Grid maintains that, at 99.99995%, the transmission system for England and Wales is the most reliable network in Europe (STC, 2015)
[20] GB has a significant amount of interconnections with other countries but they are DC, rather than AC, which isolates GB network from disturbances in neighbouring networks cascading to GB.

As power systems are more likely to be affected by large disturbances due to the reasons outlined above, the ability of critical infrastructures and services to ride through the disturbances has to be closely monitored and tested. Not only back-up supplies have to be regularly checked but also compliance with the regulations must be enforced to make sure that the infrastructures can survive large frequency deviations.

Finally, the paper considered the question of why some large-scale transmission level outages that affected hundreds of thousands of people over the last two decades attracted public attention and media coverage, and others did not. Our conclusion was that in GB at least, outages matter only if they affect critical infrastructures, especially transport, in London and the surrounding areas. What really matters to the public is not the number of people affected by a power outage, but how the disturbance affects their life. Hence if a disturbance is of a relatively short-duration and does not disrupt significantly critical infrastructures, it does not attract much attention. Also, outages affecting metropolitan areas such as London are more likely to attract the attention of media than those happening elsewhere.

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