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The Impact of Reduced System Inertia on System Planning and HVDC Interconnection

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SUMMARY

Over the past decade, significant levels of wind and solar generation have been built in Great Britain (GB). These represent non-synchronous sources of power with little or no contribution to system inertia. Further such developments are expected along with increases in HVDC interconnection capacity with mainland Europe. This paper presents a modelling framework to study the economic impact of operating a low inertia system. It is used to study a range of scenarios for the years 2020 and 2025 and provides an assessment of economic impacts of increasing GB interconnection for two sets of limits to the rate of change of frequency (RoCoF) that would arise after a loss of infeed event. The study shows that savings of between £44 million and £247 million in 2020 and up to £539 million in 2025 can be made by increasing the maximum RoCoF settings from 0.125 Hz/s to 0.5 Hz/s and the volume of curtailment of operation of renewables and interconnector imports is much reduced.

KEYWORDS

System inertia, non-synchronous generation, frequency stability, rate-of-change-of-frequency, economic assessment, HVDC interconnection

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1. Introduction

The penetration of renewable generation is on the increase in the electricity system across Europe. To facilitate and optimally utilise the connected renewable generation resources, the European Commission (EC) has proposed an ambitious target of 15% import capacity as compared to the installed generation capacity for all member countries by 2030 [1]. Historically, the EC has promoted the development of HVDC interconnectors in parallel to market liberalisation, as interconnectors are considered a fundamental prerequisite to facilitate the integration of renewable generation and ensuring fairness in European electricity markets. The current EC interconnection target of 10% by 2020 has already seen completion of several interconnection projects across Europe due to the economic opportunities afforded by increased interconnection and special funding and regulatory provisions from the EC e.g. interconnection projects included in the list of Projects of Common Interest (PCI) [2]. The projects in the PCI list benefit from accelerated licensing procedures, improved regulatory conditions, and some will have access to financial support. Some of the completed and under construction interconnection projects include The Cobra Cable project [3] of 700 MW capacity and 325 km link between Denmark and Netherlands, Piedmont-Savoy [4,5] link of 1200 MW and 190 km link between France and Italy, and IFA2 project [4] with 1000 MW capacity between France and Great Britain.

At the time of writing, the electricity system in Great Britain (GB) has 5 GW of interconnection capacity (4 GW to mainland Europe and 1 GW to the island of Ireland). This represents approximately 6% of import capacity as compared to the transmission connected installed generation capacity in GB [5]. Planned new interconnection projects to France, Ireland, Denmark and Norway would increase GB interconnection capacity by 150% by 2025 [6].

System inertia is a key factor of a power system that facilitates the security of supply as it determines how rapidly the system frequency will change in response to a disturbance. The maximum rate of change of frequency is inversely proportional to the system inertia. RoCoF (rate of change of frequency) relays, widely used in GB and Ireland to provide loss of mains (LoM) protection to distributed generation, could be triggered if the RoCoF is above a certain limit, and may lead to cascading events. Although the current RoCoF limit in GB is 0.125 Hz/s, there are plans in place to update the LoM protection settings to match the those described in the Engineering Recommendation G59 [7] by 2022 through the accelerated loss of mains programme [8]. It should be noted that while most plants will be upgraded to a 1 Hz/s RoCoF relay setting with a 500 ms detection window some existing plants are permitted to operate with a 0.5 Hz/s RoCoF setting. HVDC interconnection, wind and all solar generation represent non-synchronous sources of power with no contribution to system inertia. With increasing interconnection and penetration of converter connected renewable generation in our electricity systems, the system's total inertia, as would be determined by an unconstrained least cost dispatch of available power, is decreasing.

While the development of wind and solar generation and interconnection capacity are essential steps towards decarbonisation of the electricity system, there are concerns that the GB system may not be able to fully accommodate the potential of connected non- synchronous sources due to risks posed to frequency stability. In order to avoid such problems, the system operator must take balancing actions in critical hours to increase the system's inertia or reduce the size of the single largest loss of infeed.

This paper presents a framework to quantify the cost of re-dispatch actions due to the RoCoF related constraints and in doing so makes a case for including this analysis as part of the cost-benefit analysis (CBA) of generation and interconnection investments. The paper argues that, without advances in the management of RoCoF related constraints, adding renewable generation and interconnection to the GB system will increase the cost of managing RoCoF constraints. The magnitude of these costs is such that it cannot be ignored in the CBA and therefore it is important that care is taken in making judgements about the potential benefits derived from the proposed investments in interconnection and renewable generation. The proposed framework is demonstrated on the GB electricity system. Findings for the years 2020 and 2025 show that accommodating large penetrations of non-synchronous generation (include HVDC interconnector imports) and increasing the magnitude of the largest system loss of infeed risk, by building larger power plants or interconnections, can have a significant impact on the balancing costs.

Table 1 presents the transmission capacities and timeline of interconnection projects in Great Britain that are deemed likely or plausible by 2025. As noted earlier, the current capacity of GB interconnections is 5 GW. Interconnections to France (ElecLink, IFA2) and Norway (NSL) are in advanced stages of construction and are likely to come online by the end of 2021. There are also other proposed interconnections to Ireland, France and Denmark that have been approved by the relevant regulators and are planned to come online by the year 2023.

Table 1: Existing and planned HVDC interconnection projects in Great Britain

Name	Connected Market	Capacity (MW)	Commissioning Date
IFA	France	2000	1986
Moyle	Ireland SEM	500	2002
BritNed	Netherlands	1000	2011
EastWest	Ireland SEM	500	2012
Nemo	Belgium	1000	2019
ElecLink	France	1000	2020
IFA2	France	1000	2020
NSL	Norway	1400	2021
GreenLink	Ireland SEM	500	2023 or later
FABLink	France	1400	2023 or later
Viking	Denmark	1400	2023 or later

The main contributions of the paper are as follows:

- a framework that can be used for quantification of balancing costs due to reduced system inertia;
- a European scale electricity model that is used to inform the GB imports for future years 2020 and 2025;
- representation of system stability constraints using a plane that provides a relationship between maximum loss of infeed, total system demand and allowable non-synchronous penetration; and,
- use of scenarios to capture the uncertainty in realisation of the GB interconnection projects.

The rest of the paper is organised as follows: Section 2 presents the methodology used to quantify the impact of increasing non-synchronous generation in the GB system. A set of interconnection scenarios are outlined in Section 3 that represent the expected GB interconnection in future years of 2020 and 2025. The results are presented in Section 4 and the conclusions are presented in Section 0.

2. Methodology

This paper presents a study to determine the system non-synchronous penetration (SNSP) limits in GB, and an assessment of the economic impacts of curtailment of non-synchronous sources. The study assesses scenarios for the years 2020 and 2025 and makes use of the following three system models that have been developed at the University of Strathclyde:

1. a GB system model for assessing frequency stability;
2. a European wholesale market dispatch model built using the ANTARES platform developed by the French system operator, RTE [9]; and
3. a GB re-dispatch (balancing mechanism) model to quantify the economic cost of compliance with system constraints not accounted for by the wholesale market [10].

The frequency stability model is used to identify operational conditions where, following a given loss of infeed event, either the RoCoF limit or the limit on an acceptable frequency nadir is exceeded; and then, across a wide range of conditions, this model is used to identify the SNSP limit and its relationship with demand. The European dispatch model is used to determine wholesale market dispatches of generation and interconnector transfers under a range of demand, renewable generation availability and interconnection capacity scenarios. The re-dispatch model is then used to mimic system operator actions in the GB Balancing Mechanism to re-dispatch either or both generation and interconnector transfers in those hours in which the relevant SNSP limit would be breached.

The European dispatch model makes use of the 2020 and 2025 national generation capacity and demand scenarios provided in the Ten Year Network Development (TYNDP) plan of ENTSO-E [11] to determine hourly dispatches of GB interconnector. The re-dispatch model then tests each hour of those years and optimally re-dispatches the GB system to make it compliant with the SNSP constraint. The re-dispatch costs are based on historical bid and offer costs from GB balancing mechanism data.

2.1. The European Dispatch Model

The electricity dispatch model is built using a platform provided by the French transmission system operator called ANTARES [11,14]. The overall mathematical formulation takes the form of a unit commitment problem with weekly blocks that are coupled by the constraints on reservoir capacities [12]. Some important features of the European dispatch model are discussed in the following subsections.

Figure 1 shows the spatial scale of the model: each country is represented by a single node (except for Denmark and the United Kingdom which are split into two nodes, respectively). The ‘to’ and ‘from’ net transfer capacities (NTCs) between the countries are obtained from the Ten Year Network Development Plan (TYNDP) of ENTSO-e [11].

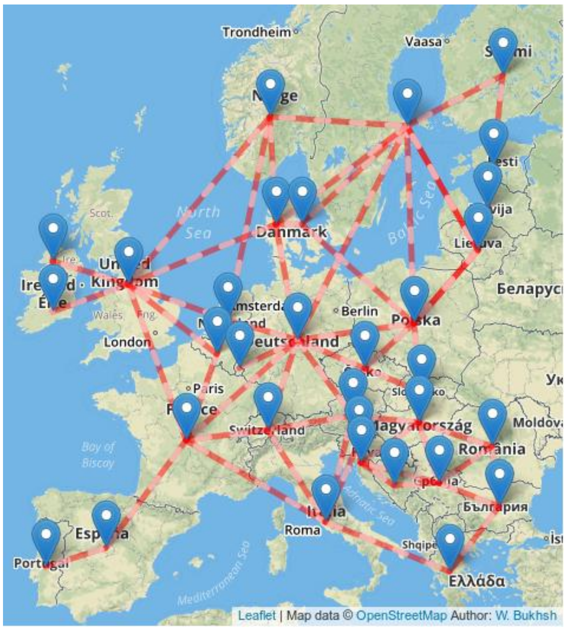


Figure 1: A representative European electricity transmission network. Each country is represented by at least a node. The Net Transfer Capacities (NTC) are used to model the capacities of the links between the nodes and are obtained from the Ten Year Network Development Plan (TYNDP).

The European dispatch model is simulated for 1-year with a time resolution of 1-hour. This time resolution requires hourly time series of input parameters like demand, available renewable generation, availability of hydro resources as well as the market cost of, and planned outage schedules for, the fossil fuel generation capacity in each country.

The generation capacities and time-series demand data are obtained from the TYNDP, which provides best estimates for the generation capacities in each country for the future years. The generation types represented in the European dispatch model are shown in Table 2.

Table 2: Generation types represented in the European dispatch model

Type	CO2 Emission (Thermal, kg/GJ)	Efficiency (%)
Biofuels	0	40
Gas - Low	57	44
Gas – Med	57	52
Gas – High	57	58
Hard Coal	94	40
Lignite	101	40
Nuclear	0	33
Oil	100	35
CHP	57	58
Other RES	0	40
Other Non-Res	100	35

The focus of this paper is on the GB power system and since the total capacity of gas generation is very high in the GB power system, it is split into three categories of low, medium and high, based on its efficiency, as shown in Table 2.

Planned and forced outages are modelled using the typical reliability statistics of each generation type. Planned outages in Europe are normally scheduled outwith the winter months to maximise availability when the demand for electricity is high. To model this, 85% of planned outage events for each generation type are set to occur outside of winter months.

The wind and solar profiles are based on the historical weather year of 2007 and are obtained from Renewable Ninja [13]. Solar generation is modelled as a fixed generation infeed to the system, whereas wind generation can be curtailed at a price.

Hydro generation is split into three categories: run-of- river (ROR), pumped storage and reservoir storage. Historic data on realised hydro generation in each European country is used to model the three hydro generation types. The ROR is modelled as fixed generation that varies over the year depending on the amount of water in the rivers. Pumped storage is controllable and the optimisation decides on the amount that is pumped or discharged from pumped storage facilities in each country. Reservoir storage hydro generation is scheduled via a weekly optimisation, with a monthly constraint on availability.

The marginal cost of a generator depends on a number of things: fuel cost, plant efficiency, start-up cost, shut-down cost and per MWh CO_2 emissions. The data for these parameters are taken from the TYNDP report [11]. In reality, the prices offered by the fossil fuel generators vary based on location and throughout the year depending on underlying fuel prices. To approximate such variations, a daily price modulation of ±2% is applied to all CO_2 emitting generation such that prices are not uniform in each country and a ±5% annual variation is applied to the central cost estimate to reflect higher winter and lower summer fuel prices.

Fossil fuel electricity producers in the UK currently pay an additional tax which is called carbon price support (CPS) [14]. Currently the CPS is £18/ton of CO_2 emission. This carbon levy is imposed in the model, which makes UK fossil fuelled generation more expensive than the equivalent mainland European generation.

2.2. The GB System Model for Frequency Stability Assessment

A 'single-bus' GB frequency stability model is used to identify operational conditions where, following a given loss of infeed event, either or both RoCoF and statutory frequency nadir limits are breached; and then, across a wide range of conditions, this model is used to characterise the SNSP limits. This model, illustrated in Figure 2, is built on a platform provided by DigSILENT PowerFactory [15]. The model neglects the spatial distribution of generators and loads, and treats them as being connected to a single busbar. It is an aggregation of elements in the power system based on how they respond to frequency events, allowing for convenient representation of operational conditions and response providers whilst maintaining an accurate assessment of system frequency behaviour during a loss event.

Figure 2 presents the key elements of the model. The FSG (Flexible Synchronous Generator) and FNG (Flexible Non-synchronous Generator) elements of the model are the generation elements that provide active power response to a frequency imbalance via controller actions. As a synchronous machine, FSG also provides an inertial response to the frequency event, while FNG does not. The ISG (Inflexible Synchronous Generators) and ING (Inflexible Non-synchronous Generators) elements of the model are generation elements with no controller action in response to a frequency event. However, ISG does provide an inertial response. It should be noted that FNG and ING can also include interconnector imports when applicable to the scenario. Within the dispatch, an inertia constant of 6 seconds is assumed for all gas units and 4 seconds for all other synchronous generators; these values are chosen following discussions with industry experts.

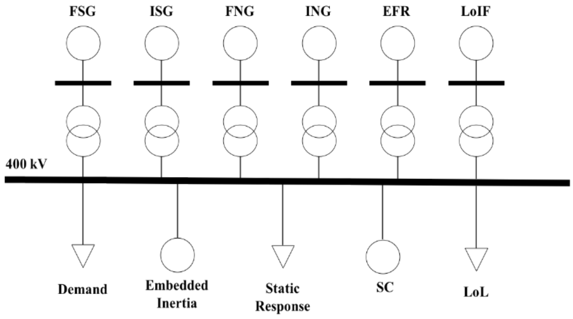


Figure 2: Graphical illustration of the single bus model that is used in this study the frequency stability assessment of the GB electricity system.

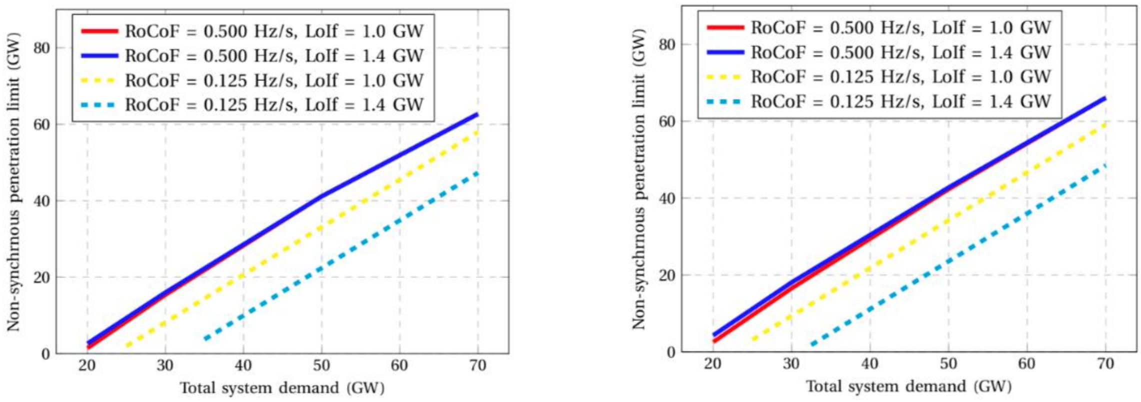
The Enhanced Frequency Response (EFR) and Static Response elements represent their corresponding frequency services, while SC allows representation of Synchronous Compensators. The Demand element refers to demand on the transmission system, i.e. the power exported to the distribution network, and includes pumped hydro, interconnector exports and net unmetered embedded generation. The default value for the sensitivity of demand to frequency is 2.5%/Hz [16]. The Embedded Inertia element represents the inertia associated with synchronous machines (generators and motors) operating within the distribution network. Based on discussions with industry experts embedded inertia is assumed to be equivalent to an inertia constant of 1.83 seconds as applied to the total transmission system demand.

All frequency response in the modelling is assumed to by dynamic and the details behind the services modelled are presented in Table 3. The study conducted focuses on containment. As a result, no additional frequency restoration services were explicitly modelled. It is assumed that any such additional service will be made available by the GB ESO to restore the power system within acceptable frequency conditions as defined in the SQSS [20]. In practice, such services include the provision of static secondary frequency response.

Table 3: Assumptions used in the paper for the three frequency response services

Enhanced Frequency Response (EFR)	Full delivery of response for a 0.5 Hz deviation in frequency and sustained for 15 minutes. This service further defines a product with a maximum of 500 ms detection and instruction delay, such that the response is fully delivered within 1 second. Dispatched at a fixed value of 201 MW.
Primary Frequency Response	Full delivery of active power response 10 seconds after the event with a 2 second delay and sustained for a further 20 seconds. While there is a definition for a dynamic secondary response service there exists no dynamic secondary only product because in practice dynamic secondary response is delivered as an extension of primary response.
Secondary Frequency Response	Full delivery of active power response 30 seconds after the event and sustained for 30 minutes.

Figure 3 presents the results of the frequency stability model. These figures for the years 2020 and 2025 establish a relationship between total system demand and maximum non-synchronous penetration in a system for a given RoCoF and LoIf (Loss of maximum infeed) values. The difference between Figure 3(a) and Figure 3(b) is because they are derived from different background generation mix in the years 2020 and 2025, respectively which alters the availability of both baseload and primary response capable generation technologies.



(a) Year 2020 (b) Year 2025

Figure 3: Graphs that represent a relationship between total system demand and the maximum allowable non-synchronous penetration in a system

2.3. The GB Balancing Mechanism Model

The balancing mechanism is a tool used by the electricity system operator, National Grid ESO in Great Britain, to balance electricity supply and demand close to real time. The balancing mechanism solution is such that it respects network and security constraints of the system. National Grid is obliged to secure the system according to the conditions laid down in the SQSS. The SQSS stipulates acceptable frequency conditions for a loss of infeed (generation) or loss of load. The biggest loss of infeed (or load) could be from the HVDC interconnector(s) when they are importing (exporting) power, or a transmission asset outage which in turn results in the loss of infeed or load.

The system operator may accept a 'bid' or 'offer' from a market participant to either decrease or increase generation (or increase or decrease consumption). They might do this, for example, to commit thermal generation that would increase inertia in the system, or to limit the output of the largest infeed(s) thus reducing the size of the infeed loss to be secured against. The trade-off between the maximum loss of infeed and amount of non-synchronous penetration is modelled via means of a constraint function, as shown in Figure 4. The plane shown in the figure is constructed from the inputs provided by the system frequency model (red dots shown in Figure 4) and establishes a relationship between the total system demand, maximum loss of infeed and the maximum allowable system non-synchronous penetration. The actions of the system operator to re-dispatch generation, curtail renewable generation and/or minimise maximum loss of infeed are modelled via means of an optimisation problem. This finds the least cost solution such that the committed generation in each hour respects the SNSP constraint derived from the frequency stability model. The above formulation is implemented using an open-source tool (OATS) [10] and the resulting linear optimisation problems are solved using a solver cplex [17]. Table 4 presents the 'bid' and 'offer' prices used in this paper to re-dispatch the generation such that it satisfies the constraint modelled using a plane as shown in Figure 3.

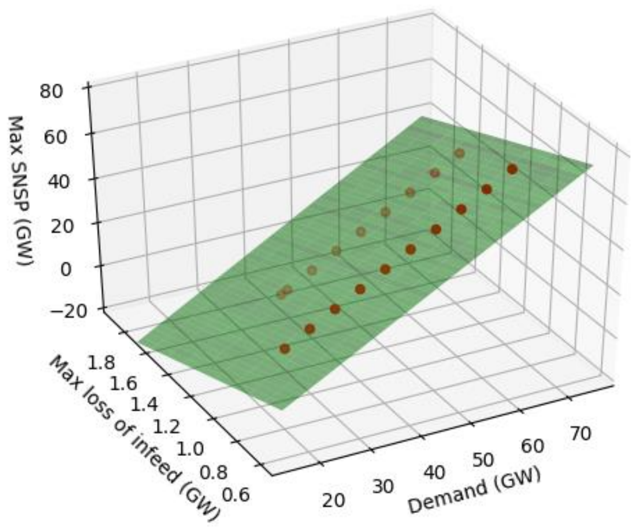


Figure 4: A plane is constructed using the points from the GB stability assessment model that provides a trade-off between system demand, maximum loss of infeed and the maximum system non-synchronous penetration in a system

The objective function of the optimisation is to minimise the total cost of re-dispatch subject to meeting the constraint as defined by the equation of the plane. The optimisation will determine a least cost solution that might include curtailment of non-synchronous generation or reducing the maximum loss of infeed to allow the given non-synchronous penetration in the system.

Table 4: Balancing costs used in the paper are derived from the accepted bids and offers in the year 2018 and are averaged for the accepted volumes for each generation type. A negative value means that a generator is willing to pay (savings in fuel) to the system operator to decrease its output.

Generation Type	Bid (£/MWh)	Offer (£/MWh)
Gas	-38.6	80.4
Coal	-44.2	82.1
Hydro	-13.4	92.8
Pumped Storage	0.6	107.4
Biomass	7.8	70.5
Wind	71.8	-

3. Interconnection Scenarios for Great Britain

Table 1 presented a list of planned and existing GB interconnection. While all the interconnection mentioned in the table are planned to be commissioned by 2023, there remains uncertainty about their actual commissioning date. To model that uncertainty, a range of GB interconnection scenarios are developed for the generation background years of 2020 and 2025.

Table 5 presents 5 GB interconnection scenarios for the year 2020 with total GB interconnection capacity varying from 5 GW to 8.4 GW. The first scenario is the today's case with 5 interconnections. Table 6 presents the GB interconnection scenario for the year 2025. With work ongoing on ElecLink, IFA2 and NSL, our best estimate is that these projects will be online by 2025. The other 7 GB scenarios model a range of possibilities on realisation of further planned interconnection projects. In total, we analyse 8 GB interconnection scenarios for the year 2025, with GB interconnection capacity varying from 8.4 GW to 13.1 GW.

Table 5: Five GB interconnection scenarios for the year 2020

Scenario	GB Interconnection	Connecting Market(s)	GB Interconnection Capacity (MW)
S_1^{2020}	Existing	-	5000
S_2^{2020}	S_1^{2020} + ElecLink	France	6000
S_3^{2020}	S_2^{2020} + IFA2	France	7000
S_4^{2020}	S_2^{2020} + NSL	Norway	7400
S_5^{2020}	S_4^{2020} + IFA2	France	8400

Table 6: Eight GB interconnection scenarios for the year 2025

Scenario	GB Interconnection	Connecting Market(s)	GB Interconnection Capacity (MW)
S_1^{2025}	Best estimate :=S_5^{2020}	-	8400
S_2^{2025}	S_1^{2025} + GreenLink	Ireland	8900
S_3^{2025}	S_1^{2025} + VikingLink	Denmark	9800
S_4^{2025}	S_1^{2025} + FabLink/GridLink	France	9800
S_5^{2025}	S_3^{2025} + GreenLink	Ireland	10300
S_6^{2025}	S_3^{2025} + FabLink/GridLink	France	11200
S_7^{2025}	S_5^{2025} + FabLink/GridLink	France	11700
S_8^{2025}	S_5^{2025} + FabLink + GridLink	France	13100

4. Simulation Results

The simulation framework presented in Section 2 of this paper is used to quantify the impact of increasing GB interconnection for the years 2020 and 2025 through the scenarios presented in Section 3.

Table 7 presents the results for the five GB interconnection scenarios for two values of RoCoF. The table presents the number of hours the constraint for non-synchronous penetration would be violated as well as the cost of re-dispatch to correct the solution. As would be expected, both the number of hours and the cost of re-dispatch for the RoCoF limit of 0.125 Hz/s is much higher than the RoCoF limit of 0.5 Hz/s. Across all the five scenarios, on average the cost of re-dispatch to respect the SNSP constraint with a ROCOF limit of 0.125 Hz/s is 6 times higher than if the RoCoF LoM settings were to be changed to 0.5 Hz/s. Figure 5 presents the data of Table 7 graphically and illustrates the increasing cost of re-dispatch with increasing GB interconnection, but with very different magnitudes for the two RoCoF settings. The main reason of the increasing cost of re-dispatch with increasing GB interconnection is that the GB is connecting to relatively cheaper markets in Europe through the interconnectors which result in greater imports and hence leading to more hours where the system non-synchronous penetration limits are violated.

Table 8 presents the results of the eight GB interconnection scenarios as defined in Table 6. To take account of uncertainty in the relative future prices of gas and coal, two generation merit order scenarios are considered, applied across the whole of Europe: Gas before Coal and Coal before Gas along with the two RoCoF settings of 0.125 Hz/s and 0.5 Hz/s. In total 32 scenarios were simulated for the year 2025. The first scenario for the year 2025 is the same as 2020 scenario 5 in terms of the GB interconnection capacity. However, the generation background assumptions taken from the ENTSO-e TYNDP are different and generally have more renewable generation capacity available in

2025 than 2020. An interesting thing to note is that the number of hourly violations (and the cost of re-dispatch) goes down in scenario 2 as compared to scenario 1. This is because in scenario 2, GB is connected to the Irish electricity market via the 500 MW GreenLink. The Irish market is relatively expensive and the new interconnector facilitates more imports from GB and hence reduces the numbers of hours the SNSP constraints are violated in GB[2]. The same is true for scenario 5 that has less hours of constraint violation when compared to scenario 4. In all other scenarios, the cost of re-dispatch is increasing with respect to increasing interconnection capacity. The annual cost of re-dispatch for the 0.125HZ/s RoCoF setting is extremely high across all the 2025 Coal before Gas scenarios ranging from £420m-£565m. Figure 6 presents the number of hours the SNSP constraint is violated.

Table 7: Results for the year 2020 for five GB interconnection scenarios and two RoCoF settings.

Scenario	RoCoF limit (Hz/s)	No. of hours	Annual cost of re-dispatch (£m)
S_1^{2020}	0.125	658	48.53
	0.500	47	4.91
S_2^{2020}	0.125	807	79.86
	0.500	82	10.90
S_3^{2020}	0.125	944	116.63
	0.500	126	20.95
S_4^{2020}	0.125	2068	350.73
	0.500	1079	105.81
S_5^{2020}	0.125	2363	399.04
	0.500	1306	152.49

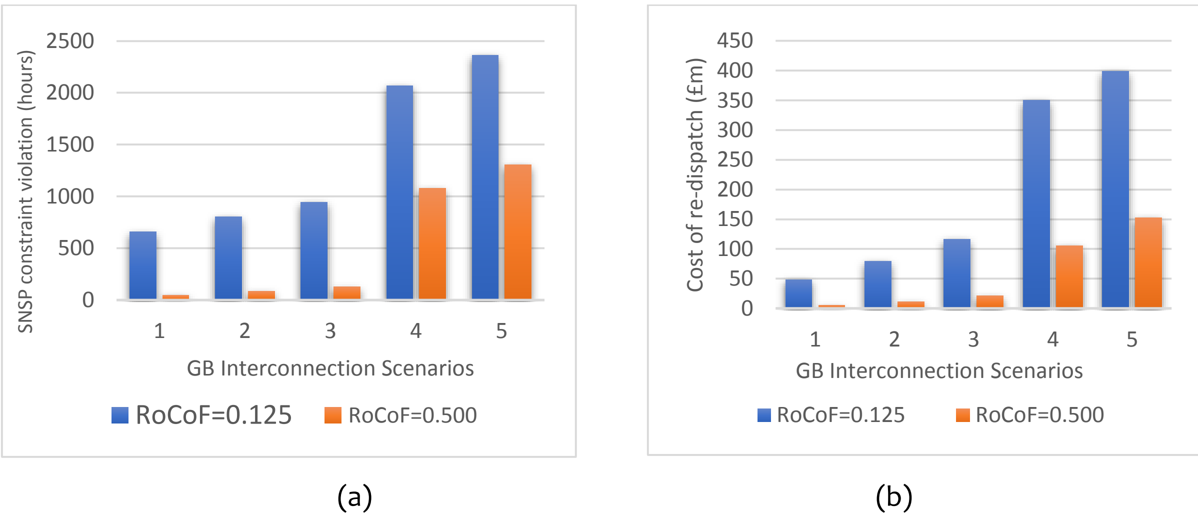


Figure 5: The impact of increasing the GB interconnection capacity in 2020 on a) the number of hours in a year the SNSP limit is violated and b) the cost of re-dispatch to correct the violation.

2 Note that the SNSP constraint on the island of Ireland was not modelled.

Table 8: Results for the year 2025 for eight GB interconnection scenarios, two generation merit order scenarios and two RoCoF settings.

Scenario	Merit Order	RoCoF (Hz/s)	No. of hours	Annual cost of re-dispatch (£m)
S_1^{2025}	Gas before Coal	0.125	341	112.31
		0.500	4	0.47
	Coal before Gas	0.125	1543	458.09
		0.500	78	10.59
S_2^{2025}	Gas before Coal	0.125	306	106.54
		0.500	1	0.09
	Coal before Gas	0.125	1504	423.52
		0.500	47	8.14
S_3^{2025}	Gas before Coal	0.125	336	107.38
		0.500	3	0.34
	Coal before Gas	0.125	1536	446.82
		0.500	74	13.86
S_4^{2025}	Gas before Coal	0.125	825	269.19
		0.500	35	5.45
	Coal before Gas	0.125	2052	518.46
		0.500	215	21.97
S_5^{2025}	Gas before Coal	0.125	763	178.64
		0.500	31	4.86
	Coal before Gas	0.125	1835	482.18
		0.500	177	19.37
S_6^{2025}	Gas before Coal	0.125	798	221.46
		0.500	56	6.38
	Coal before Gas	0.125	2097	528.49
		0.500	193	23.11
S_7^{2025}	Gas before Coal	0.125	806	230.71
		0.500	63	7.20
	Coal before Gas	0.125	2128	536.18
		0.500	208	23.62
S_8^{2025}	Gas before Coal	0.125	824	238.19
		0.500	71	7.91
	Coal before Gas	0.125	2156	565.02
		0.500	223	25.61

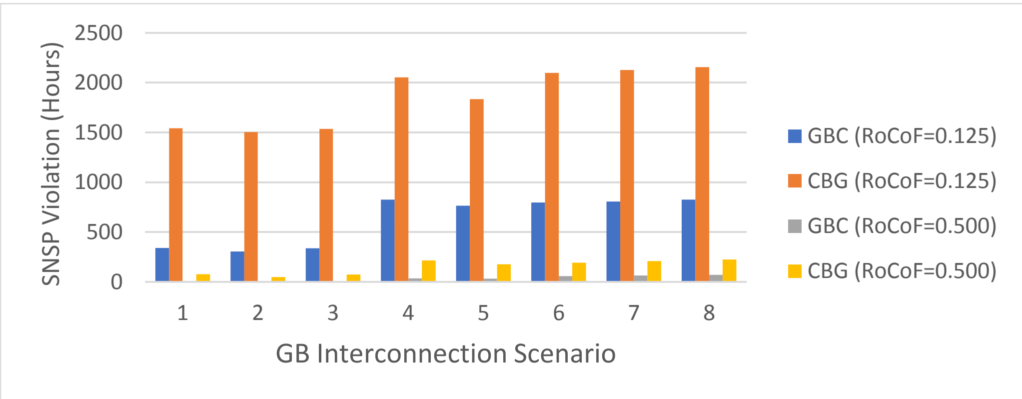


Figure 6: Number of hours the system non-synchronous penetration (SNSP) limit is violated for the 32 cases considered for the year 2025

5. Discussion and Conclusions

At the time of writing, the accelerated loss of mains programme is underway in Great Britain to upgrade settings of RoCoF relays from 0.125 Hz/s to 1 Hz/s measured over 500 ms and to remove vector shift (VS) relays when these are used for the LoM protection [8]. This matches Engineering Recommendations G59 and given the extremely low system inertia values that it accommodates, even if some plant remains on a 0.5Hz/s RoCoF risk, it is unlikely that there would be a need for further upgrades to the settings. With approximately 50,000 distribution generation sites supplying 15 GW, the programme presents numerous challenges and is largely reliant on a financial incentive scheme to encourage participation which covers costs of £1000-£4000 per upgrade or replacement. Nevertheless, the ESO expect the programme to be completed by April 2022. While the upgrades are being carried out, the current practice of managing risk is by limiting the largest loss of infeed and increasing the inertia in the system, which cost approximately £150million in 2018 [22]. The study in this paper shows that savings of between £44 million and £247 million in 2020 can be made by increasing the maximum ROCOF settings from 0.125 Hz/s to 0.5 Hz/s and the volume of curtailment of operation of renewables and interconnector imports much reduced. In addition, innovations in the provision and delivery of frequency response services [23] may improve the system's non-synchronous penetration limit, and thus reduce the number of hours in which it is binding and the associated constraint costs.

The cost savings of successfully changing RoCoF settings by the year 2025 (or risks associated with failing to do so) are found to be between £106 million and £539 million. The large variation in 2025 is due to the 32 quite different GB interconnection and generation cost scenarios considered in the paper. The results in the paper highlight the need for flexibility in our system so that renewable non-synchronous generation can be optimally utilised.

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