Capacity value of interconnectors for resource adequacy assessment in multi-region systems

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***Abstract*—Interconnectors can enhance resource adequacy in multiple regions of an interconnected system, but determining the value of their contribution, and how it is shared between the regions, is non trivial. This paper introduces the concept of minimum equivalent firm capacity (MEFC) to determine the minimum additional generation which would be required to provide the same reliability benefit as an interconnector, and into which regions of the system this should be installed. MEFC is calculated using a linear program as a heuristic to identify the optimal ratio in which the MEFC should be installed. The reliability of the system is evaluated using a sequential Monte Carlo simulation, with an efficient convex optimization used to dispatch interconnectors and energy storage. The optimality of the heuristic approach is investigated, and the method is demonstrated on a three-region system of Great Britain, Ireland, and France with the addition of the proposed Celtic Interconnector.**

***Index Terms*—Interconnection, security of supply, capacity value, power system meteorological factors**

I. Introduction

The rapid increase in renewable technologies necessitates systemic change to principles by which power system resource adequacy is assessed [1], [2]. This assessment is usually undertaken with simplified assumptions about the nature of interconnection, potentially failing to understand likely flows that occur during power system extremes which ultimately give rise to possible shortfalls. This issue is particularly pertinent given the rise of weather-dependent renewables, which lead to new spatiotemporal coupling on the supply side, and a rapid increase in planned interconnection in places such as Northwest Europe.

Electricity interconnectors are controllable links between otherwise independent regions of electric power systems. For the purposes of this paper, a *system* consists of multiple interconnected *regions*. Each region represents a well-connected power system (e.g., Great Britain's power system) and the capacity of between-region interconnection is small relative to the size of the interconnected regions (and therefore likely to be frequently operated at maximum capacity). As well their primary function of supporting economic system operation [3], interconnectors can provide capacity to address resource adequacy issues by transferring power during peak periods. In this paper, we look to measure this contribution by assessing the *capacity value* of interconnectors in an interconnected system–that is, the ability of the interconnector to reduce the risk of a shortfall in generating capacity. This value has been appreciated in power systems for many years [4], [5], but the new challenges facing modern power systems, as well as the change in the drivers of system shortfalls, have driven renewed interest in the topic.

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A. Capacity Value of Interconnectors

Capacity value is a means of quantifying the contribution of an asset to the resource adequacy of a system by making it analogous to a conventional asset. Interconnectors provide a controllable source and sink of electrical power for each region on the condition that there is the capacity to provide or absorb the power in the interconnected system. This means interconnectors can improve resource adequacy in both regions on the condition that there is spare generator capacity in one region when there is a shortfall in the other. The spare generation capacity in each region is a function of the available conventional generator capacity, the demand, and the output of any renewable generation. The second and third of these are driven – to a greater or lesser extent – by the weather conditions within each region.

In an ideal case – with perfectly reliable and efficient interconnectors, and in which stress events are never concurrent in the interconnected regions – an interconnector would have an equivalent firm capacity (EFC) of twice its nameplate rating, shared equally between the two regions [6]. However this is unlikely to occur in practice: stress events will sometimes occur concurrently in interconnected regions, so the capacity value of the interconnector will be less than the ideal case, and will be different for any given pair of interconnected regions.

Contemporary research on the capacity value of interconnectors is relatively limited. Tindemans et al. [7] studied the capacity value of an interconnector between two regions using Monte Carlo simulation. The impact of different policies on capacity value was investigated, and a "share" policy, in which the two regions maximise their combined reliability without acting 'selfishly' to minimise their own risk, delivered the best outcomes. Sanchez et al. [8] also investigated a two-region interconnected system and the impact of system operator policies, but used a hindcast approach. Their results reinforce that a sharing policy delivers the best overall outcome, but find that it may trade a reduction in reliability in one region for an increase the other. Hagspiel et al. [6] study the capacity value of interconnection between different neighbouring pairs of European countries using probabilistic optimization. In some cases, the interconnectors deliver almost their theoretical maximum capacity value, whilst in others they provide zero reliability benefit. In general, existing research deals with two-region systems and avoids the complexity of capacity value metrics for a multi-region power system.

The main contribution of this paper is to address this gap by proposing and evaluating a systematic method to determine the capacity value of new interconnection in multi-region power systems. It is shown that the traditional capacity value definition of the Equivalent Firm Capacity (EFC) as a root-finding problem must be augmented to instead be a constrained optimization problem, with the solution determining not only the EFC but also optimal fraction of this capacity that is allocated to each region. We evaluate the suitability of our approach considering both local and global properties of the three-region system of France, Great Britain (GB), Ireland, considering the planned Celtic interconnector between France and Ireland as a case study.

II. Methodology

This section describes the methodology used to assess the capacity value of interconnectors. The reliability of the system is assessed via convex optimisation embedded within a sequential Monte Carlo framework. The capacity value is calculated as the minimum set of ideal firm generators which could be installed across the interconnected regions to deliver the same reliability improvement as a new interconnector.

A. Capacity Value Metrics in Single Region Systems

There are different capacity value metrics, which use different conventional assets: EFC is the perfectly reliable conventional generator which would result in the same improvement in system reliability as the new asset [9]; effective load carrying capacity (ELCC) is the additional demand which can be accommodated in the system while maintaining the reliability performance of the original system [10]; equivalent conventional capacity (ECC) is similar to EFC, but the analogous conventional generator is assigned an assumed availability [9]. ECC has the theoretical advantage that it doesn't treat conventional capacity as being perfectly reliable, but is sensitive to the assumed reliability. EFC and ELCC are more widely applied, with EFC being used in generation-based studies at transmission level, and ELCC used in network-based studies at distribution level; in some circumstances, EFC and ELCC are equivalent [11]. EFC is used in this paper be because it is used in equivalent planning studies within industry.

These single-region metrics are quantified by solving a root-finding problem. For example, to determine the EFC of a non-firm asset in a single-region system, the value of a risk metric (e.g. expected energy not supplied (EENS)) is found for a set of points, which are then used to determine the capacity value to a suitable level of precision using an appropriate numerical scheme (e.g. bisection).

B. Quantifying Capacity Value in Multi-Region Systems: the Minimum Equivalent Firm Capacity

In contrast, when a system comprises multiple regions, each having its own reliability, the hypothetical firm capacity required to calculate the EFC could be installed in any of those regions. The impact of this capacity on system risk will be different for each region, and this impact will change as more capacity is installed. Consequently, the EFC should be determined as a function of the ratio by which additional capacity is installed in each region.

This point can be observed for a hypothetical GB-FR-IE three region system in Fig. 1. In this example, installing new capacity in the Irish region initially results in the greatest reduction in risk for the system, and so installing new capacity in Ireland leads to a much lower calculation of EFC (the intersection between the plotted lines and the target EENS) than the installation of all of the capacity in France . However, this firm capacity need not be constrained to only be in individual countries: by sharing the generation between two or more regions a lower EFC can be achieved (e.g., with 0, 0.48, 0.52 of the capacity installed for GB, FR, IE respectively in this instance). This suggests that the capacity value of an interconnected system should be determined as the Minimum Equivalent Firm Capacity (MEFC). The MEFC is the minimum EFC that can be achieved in a given system, given all possible combinations of the hypothetical firm capacity that could be installed. This is therefore an optimization problem, rather than the root-finding problem.

C. Solution Approach using the Optimal Firm Capacity Ratio

To calculate the MEFC, an algorithm must also determine the optimal firm capacity ratio (OFCR) by which hypothetical firm generation capacity should be added to each region. For example, if a 2 GW interconnector's MEFC is 1.5 GW, with this generation split with 0.9 GW in GB, 0.45 GW in Ireland and 0.15 GW in France, this ratio is represented by the tuple (0.6, 0.3, 0.1). The OFCR will change with the target EENS (and therefore the size of the proposed asset).

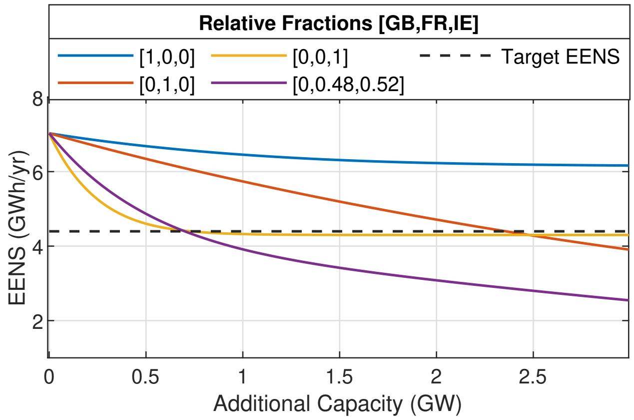

Fig. 1. The rate at which EENS for the whole system reduces as firm capacity is added to the regions according to different firm capacity ratios.

If the OFCR was known a priori, then calculation of the MEFC then collapses back to a root-finding problem for which standard techniques exist (Section II-A)). We take advantage of this point in the approach taken in this work (Section II-E): the OFCR is estimated using a heuristic method (based on the solution of a Linear Program); then the MEFC is determined using a standard root-finding approach. To check the (local) optimality of the MEFC, the EFC can be calculated using ratios that are close (in some norm) to the estimated OFCR.

This approach has several advantages. Firstly, once the OFCR is determined, the subsequent root-finding problem is well-understood in the field of power system reliability. Secondly, so long as the heuristic to find the OFCR is faster than the process to evaluate the EENS, the computational complexity of finding the MEFC is then no greater than that of the determination of the EFC. Finally, although global optimization strategies are not considered in this work, numerical examples show that the approach is effective at finding a good local minima, with an estimate of the MEFC that is significantly lower than calculations of single-region EFC.

D. Reliability Assessment

The reliability of each region is determined by the availability of adequate generation capacity to meet demand. If there is adequate capacity there will be a positive margin; if there is not adequate capacity, there will be a negative margin. The margin of region i at time t is defined as

$$Z_{t,i} = X_{t,i} + Y_{t,i} - D_{t,i} + I_{t,i} + S_{t,i}\,, \tag{1}$$

where Z is the margin, X is the available conventional generation capacity, Y is the renewable generation output, D is the demand, I is the total flow into the region via interconnectors, and S is the flow into the region from energy storage. Both I and S can take negative values (if the region is exporting or the storage is charging). In each time step, if the margin of a given region is negative, there will be a shortfall resulting in a non-zero Energy Not Supplied (ENS), as

$$\mathrm{ENS}_{t,i} = \max(-Z_{t,i}, 0)\,. \tag{2}$$

In this work, the EENS is used as a reliability metric to quantify MEFC. If a sufficiently large set of ENS values is simulated, these can be used to estimate the EENS as

$$\mathrm{EENS}_i = \frac{N_{\mathrm{Season}}}{N_{\mathrm{Sim.}}} \sum_{t=1}^{N_{\mathrm{Sim.}}} \mathrm{ENS}_{t,i}\,, \tag{3}$$

where N_{Season} is the number of days over which the EENS is calculated (e.g., one year), and $N_{\mathrm{Sim.}}$ is the number of days simulated.

Finally, the EENS for the system can be determined as the sum of the EENS for each region as

$$\mathrm{EENS} = \sum_{i=1}^{N_R} \mathrm{EENS}_i\,, \tag{4}$$

where N_R is the number of regions together comprising of the system.

The EENS is evaluated using a Sequential Monte-Carlo Simulation (SMCS), based on the approach used in [12]. The behaviour of the multi-region power system is simulated over N days. For each day, coupled time-series of weather-driven demand and renewable generation are sampled from a data set and the level of available conventional generation is sampled from a probabilistic outage model. ENS for each time step and each region is calculated using (2); if there are no shortfalls (positive ENS values) the simulation moves on to the next day; if there are shortfalls, then the interconnector flows between the regions and charging and discharging of the energy storage in each region are optimised to minimise the ENS. To ensure that the SMCS gives accurate results, convergence is quantified using the Coefficient of Variation (CoV), as shown in (5). All results presented in this paper had a CoV of 1% or lower.

$$\mathrm{CoV} = \frac{\sigma}{\mu.\sqrt{\frac{N_{\mathrm{Sim.}}}{N_{\mathrm{Season}}}}}\,. \tag{5}$$

The EENS results are used to calculate the EFC using the process described in section II-E.

During periods of system stress, resource adequacy is prioritised over energy prices. Consequently, the interconnectors and energy storage assets, which can be dispatched to increase the margin in a given region, are operated to minimise ENS across N_{Day} time steps and N_R regions. The objective function,

$$\min \sum_{i=1}^{N_R} \sum_{t=1}^{N_{\mathrm{Day}}} \mathrm{ENS}_{i,t} + \varepsilon \|\mathrm{diag}(\mathbf{w})\mathbf{ENS}\|_F \tag{6}$$

minimises the global ENS while including a regularisation term which distributes ENS between regions (in proportion to their peak demand) with kth element given by

$$\mathbf{w}[k] = \frac{\left(D^k_{\mathrm{max}}\right)^{-1}}{\left(\sum_{i=1}^{N_R} D^i_{\mathrm{max}}\right)^{-1}}. \tag{7}$$

The coefficient ε is a constant with a small value which enforces the regularisation without impacting on the main objective, and $\mathbf{ENS}$ is an $N_R \times N_{\mathrm{Day}}$ matrix of the ENS in each region and each timestep.

Each region i assumed to have some volume of energy storage with round-trip efficiency η which is subject to state of charge, charging, and discharging constraints:

$$\mathrm{SOC}_{i,t+1} = \mathrm{SOC}_{i,t} + \left(P_{i,t}^{ch}.\eta - \frac{P_{i,t}^{dch}}{\eta} \right).\Delta t \quad (8)$$

$$0 \leqslant \mathrm{SOC}_{i,t} \leqslant \mathrm{SOC}_i^{\max} \quad (9)$$

$$0 \leqslant P_{i,t}^{ch} \leqslant P_i^{\max} \quad (10)$$

$$0 \leqslant P_{i,t}^{dch} \leqslant P_i^{\max} . \quad (11)$$

Because the simulations take place on a daily basis, an additional constraint is needed to ensure that the energy storage returns to its initial SOC value at the end of the day:

$$\mathrm{SOC}_{i,1} = \mathrm{SOC}_{i,N_{\mathrm{Day}}} . \quad (12)$$

Finally, a constraint is needed to ensure that the interconnector capacity limits are not violated,

$$-\mathrm{IC}_{ij}^{\max} \leqslant \mathrm{IC}_{ij,t} \leqslant \mathrm{IC}_{ij}^{\max} \quad (13)$$

where $\mathrm{IC}_{ij,t}$ is the interconnector flow between regions *i* and *j* at time *t*, and $\mathrm{IC}_{ij}^{\min}$ and $\mathrm{IC}_{ij}^{\max}$ are the minimum and maximum permitted interconnector flows, respectively.

E. Determination of Optimal Firm Capacity Ratio

The OFCR is determined by analysing the case with no additional interconnector capacity to evaluate the distribution of ENS between regions. The aim is to find the vector x_{OFCR} which minimises the total additional generation required to achieve the same EENS value as the new interconnector, where each element of x_{OFCR} represents the proportion of new generation installed in a given region. Collecting all simulated ENS matrices $\mathbf{ENS}$ for this base case into a matrix $\mathbf{ENS_{Sim.}} \in \mathbb{R}^{N_R \times N_{\mathrm{Sim.}}}$, then, under an assumption of no redispatch of interconnector or energy storage capacity, the optimal installation of firm generators between regions x_{OFCR} to minimise the expected shortfall can be formulated as a linear program. Specifically, for the installation of c GW of additional generation capacity, we can solve

$$\min_{x_{\mathrm{OFCR}}} \sum_{i=1}^{N_R} \sum_{t=1}^{N_{\mathrm{Sim.}}} \mathbf{ENS}_{i,t}^{\mathbf{OFCR}} \quad (14)$$

$$\text{s.t.} \quad \sum_{i=1}^{N_R} x_{\mathrm{OFCR},\,i} = 1 \,, \quad (15)$$

$$z_i = \mathbf{ENS_{Sim.}}_{\,i,:} - c x_{\mathrm{OFCR},\,i} \mathbb{1}^{1 \times N_{\mathrm{sim}}} \quad (16)$$

$$\mathbf{ENS}_{i,:}^{\mathbf{OFCR}} = \max\{z_i, 0\} \,, \quad (17)$$

$$x_{\mathrm{OFCR},\,i} \geq 0 \quad \forall\, i \,. \quad (18)$$

where the operator 'max' is taken element-wise and $\mathbb{1}^{n \times m}$ is the n-by-m matrix of ones. By introducing suitable auxiliary variables for the $\max$ operator, the optimization (14) to (18) takes the form a of a linear program. Note that the optimal value of x_{OFCR} changes with c.

The full algorithm for determining the EFC of an interconnector of size c_{IC} can be described as follows.

TABLE I
CASE STUDY SYSTEM PARAMETERS

Parameter name	Country Code		
	GB	**IE**	**FR**
Firm Generation Capacity (GW)	59.8	5.3	106.9
Peak Demand (GW)	55.8	6.2	88.0
Wind Generation Capacity (GW)	20	5	13
Solar Generation Capacity (GW)	10	0.5	12
Energy Storage Capacity (GW/GWh)	5/10	1/2	5/10

- The EENS is determined for the base case using the approach described in Section II-D. This is used to build the ENS matrix $\mathbf{ENS_{Sim.}}$.
- The EENS is determined for the proposed interconnector.
- The OFCR, x_{OFCR}, is then determined using $\mathbf{ENS_{Sim.}}$ and the linear program (14)-(18). This is then used in conjunction with a line search to determine the additional level of generation which results in the same EENS as the proposed interconnector.

This is a heuristic approach, as the globally optimal OFCR for determining the true EFC of the interconnector will require the redispatch of energy storage and interconnectors-however this would result in an intractable problem. Consequently, the robustness of this approach is examined in section IV-C.

III. CASE STUDY DESCRIPTION

The case study used in this paper is the GB, Irish, and French multi-region system with 2021 levels of renewable and conventional generation, demand, interconnection, and energy storage. The values were fine-tuned to align the LOLE and EENS values for the base case with those published in the 2021 winter outlook reports for those regions. The peak demand, generation, and energy storage capacities are shown in Table I. The reliability analysis was carried out in Matlab, with the optimal dispatch of interconnectors and energy storage formulated in Yalmip and solved using Gurobi. The OFCR was calculated using the Mosek Fusion API in Python.

A. The Celtic Interconnector

The Celtic Interconnector is a proposed 700 MW HVDC link between Ireland and France. The project, which is expected to enter service in 2025, will provide a direct link between Ireland and continental Europe (at present, this link only exists via GB). A diagram of this system is shown in Fig. 2 While studies on the economic impact of the Celtic Interconnector exist [3], [13], none quantify its contribution to security of supply. This is a crucial topic, since interconnection will play a key role in ensuring security of supply in net-zero power systems, particularly Ireland and GB which both have a large wind resource but, as geographical and electrical islands, must ensure endogenous adequacy of supply.

B. Data Sources

The capacity value of interconnectors depends on the coincidence of stress events in interconnected regions, which

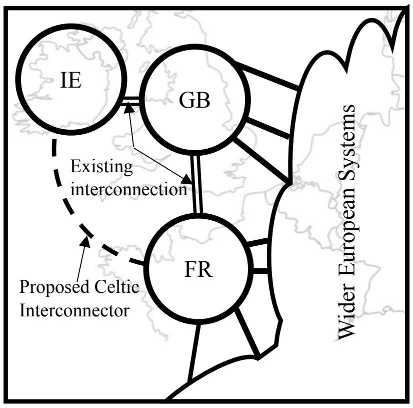

Fig. 2. The IE-GB-FR multi-region system.

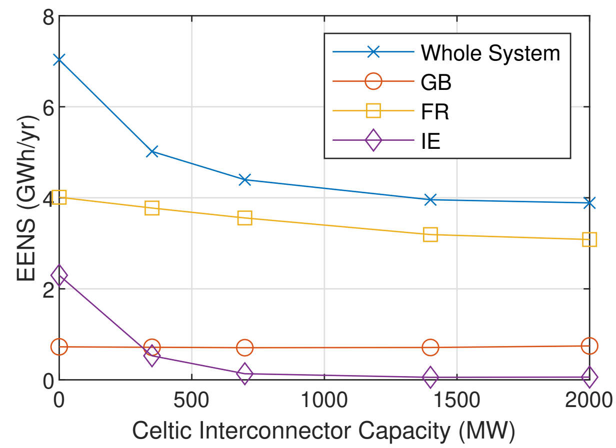

Fig. 3. The change in EENS for the whole system and each region with the installation of the Celtic Interconnector

is partially driven by the weather within those regions. This paper takes advantage of a 70-year reanalysis data set which has been developed specifically for use by energy system modellers [14]. Weather driven models of demand and renewable generation were developed; demand was modelled as a function of ambient temperature [15] whilst the renewable generation models were taken directly from [14]. Time-series of conventional generator available capacities were calculated using the models presented in [16]. Renewable generation capacities, and the location of these generators, were taken from [17]. This resulted in a 70-year time-coupled data set of renewable generation and demand for the 2021 multi-region system and climate.

C. *Simulation Scenarios*

The purpose of the simulations is to determine the capacity value and marginal capacity value of the Celtic interconnector, as well as demonstrating the accuracy of the proposed methodology. The operation of the system was simulated with Celtic interconnector capacity varying from 0 to 2000 MW. The existing interconnection between GB and France was set at 4000 MW and between Ireland and GB at 1000 MW.

IV. Results

The results from the case studies are presented in this section. The impact of the Celtic interconnector on the reliability of the system and each region is presented in section IV-A. The EFC and marginal EFC of the Celtic Interconnector are discussed in section IV-B. Finally, the optimality of the OFCR calculation described in section II-E is tested in section IV-C.

A. *Impact of New Interconnection on EENS*

The EENS of the overall system and each region are shown in Fig. 3. Overall, the EENS falls as the capacity of the new Celtic interconnector is increased. It is clear that there are diminishing returns as more additional capacity is added: the proposed 700 MW delivers most of the EENS reduction that would be delivered by a 2000 MW project.

The EENS is initially shared primarily between France and Ireland, with a smaller proportion attributed to GB; this is in line with expectations given the winter outlook reports for the three regions which formed the basis of the scenarios. When the Celtic Interconnector is installed, there is a rapid decrease in EENS in Ireland, a small decrease in EENS in France, and no change in EENS in GB. This behaviour is partially due to the regularisation term in (14), which uses the weightings (7) to allocate the ENS based on the peak demand of the regions. Ireland initially had a disproportionately high EENS relative to its peak demand, so the additional interconnection is used to reduce shortfalls there before reducing those in France (which has a higher absolute, but lower relative, EENS).

B. *Capacity Value of New Interconnection*

The equivalent firm capacity of the Celtic Interconnector and the marginal capacity value (the MEFC of adding another MW) are shown in Fig. 4. The marginal value was found by fitting a polynomial function to the EFC results and finding its first derivative. The results show that, initially, the capacity value of new interconnection is approximately 1MW per MW of installed capacity. The 700 MW case, which corresponds to the planned interconnector, has an EFC of 670 MW, which is close to 100% of the interconnector capacity, allocated as 500 MW in IE, 170 MW in FR, and 0 MW in GB.

C. *Optimality of the Proposed Approach*

The approach outlined in section II-E is simple to implement: once the the OFCR has been estimated, it is not updated in the determination of the MEFC. In reality, however, interconnectors and energy storage can be redispatched, and so the value determined may be greater than the true MEFC at a given interconnector capacity.

To determine whether a good estimate of the true OFCR has been found, we determine the heuristic OFCR estimate using (14)-(18), then use this to determine the value of the EFC. Subsequently, we introduce perturbations to the estimated OFCR, then re-calculate the EFC for each OFCR value; if the EFC of the estimated OFCR has the smallest EFC, then it can at least be considered close to a local minimal EFC.

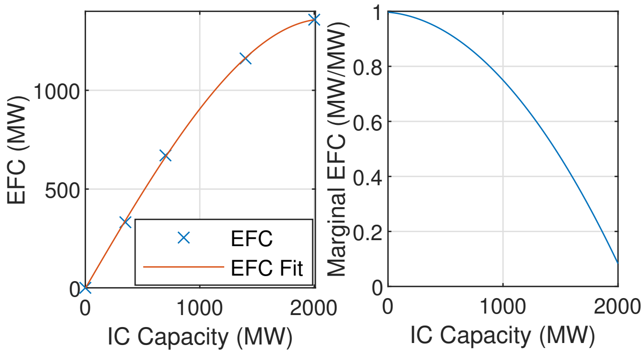

Fig. 4. The EFC of the Celtic Interconnector for different installed capacityies (left) and the marginal EFC (the EFC of the next MW) (Right)

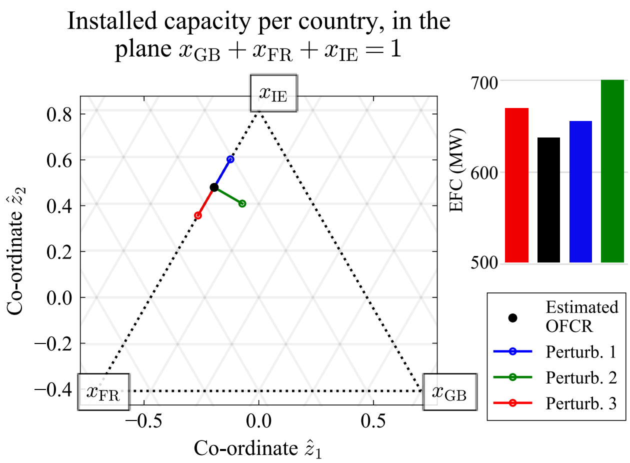

Fig. 5. The OFCR is constrained to be within the polytope described by (15), (18); in a three-region system, this set represents an equilateral triangle, here represented in co-ordinates tangent to this plane $\hat{z}_1, \hat{z}_2$. The OFCR has been calculated and perturbations parallel and perpendicular to the constraint $x_{\mathrm{GB}} = 0$ have been used to test the optimality of this solution.

For a three-region system, this process can be visualised, as the polytope (15), (18), an equilateral triangle in two dimensions. This plane, defined by $x_{\mathrm{GB}} + x_{\mathrm{FR}} + x_{\mathrm{IE}} = 1$, is plotted in Fig. 5 with the estimated OFCR (calculated by solving (14)-(18)) and perturbed OFCR values plotted within it. The inset bar chart shows the EFC calculated for these perturbations: two are parallel to the constraint $x_{\mathrm{GB}} = 0$, and one perpendicular. The blue and red bars, which estimate the gradient along the constraint, show that the EFC has increased when allocating additional generation to either the FR or IE regions. The green bar, which represent perturbations in the generator allocation to GB, show an increase in the only feasible direction. These results show that the true optimal solution is within the bound of these perturbations and therefore close to the heuristic OFCR estimate.

V. Conclusions

This paper has presented a method for quantifying the capacity value of a new interconnector between two regions of a multi-region power system. The method uses weather-based models of demand and renewable generation to capture the time-coupling between regions and models generator outages to simulate system stress events. The equivalent firm capacity metric has been updated with a novel method to avoid over-estimation by optimizing the allocation of new firm capacity.

The method has been demonstrated by evaluating the capacity value of the proposed Celtic interconnector the to the Great Britain, France, and Ireland systems. Future work could investigate the optimal placement of new interconnection, study the sensitivity of this capacity value to increased reliance on renewable generation and electrified heat, or quantify the capacity cost of a long-term interconnector outage.

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