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Energy Storage Siting and Sizing Methodology to Unlock Transmission Transfer Capacity – A Case Study in the UK National Grid

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SUMMARY

Transmission grids are operated well below their thermal capacities to ensure security of supply deliverability even under a wide range of potential equipment outages and supply interruptions. Unlocking the latent underutilized capacity of the grid while ensuring system security has a great economic value [1].

Battery energy storage systems can rapidly influence the power flow pattern and system voltages post contingencies and thus have the potential to securely increase the transfer limits across boundaries (or flow gates) up to their thermal limits. Planning the grid with battery energy storage requires careful analysis and selection of sites, sizes, lifetime economics, and control system signals and settings. These techniques are evolving, and grid planners require practical approaches to help them investigate the application of this technology.

This paper explores the technical efficacy and economics of utilizing battery energy storage systems to unlock the transfer capacity of several boundaries in the UK transmission grid. Siting and sizing of energy storage to increase the transfer capacity across one of the key boundaries are discussed in detail. Partial mitigation of the boundary congestion using hybrid solutions, which include both wires and non-wires components, is demonstrated by weighting the market benefits provided by the battery/hybrid project against its costs. The paper presents the technical approach, analyses algorithms, study results, and recommendations.

KEYWORDS
Non-Wire Solutions, T&D Applications, Congestion Relief, Energy Storage, time-series analysis, siting, sizing, techno-economic evaluations

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1. Introduction

Transmission systems are designed to interconnect generation and load areas and transfer energy efficiently while meeting a stringent set of reliability criteria [2]. Over decades, transmission networks have mainly expanded utilizing passive conventional systems known as “wires solutions” (i.e., transmission lines, transformers, switchgear), which require an operational philosophy of keeping networks almost half-loaded in a preventive operational posture in anticipation of potential contingencies that push the system towards its thermal, voltage, or stability limits. Networks are restricted 100% of the time from reaching their full capability in transferring power from low-cost production regions to high-cost load centers due to events that typically last less than 2% of the time. These prudent operational restrictions, dictated by the capability of the conventional systems that make up transmission networks, lead to congestion costs that can have significant economic impacts on many stakeholders [1,4].

Energy storage systems offer many potential benefits to transmission and distribution (T&D) systems due to the ability of modern power electronics, and some electro-chemistries, to rapidly change from full discharge to full charge modes, or vice versa [3]. These characteristics have led to increasing interest in utilizing energy storage systems to economically unlock the inherent transmission grid capacity. Strategic siting and sizing of storage resources will allow the operators to load the grid above its contingent capacity and closer to its intact or normal system capacity, and to utilize the strategic storage resources to absorb or inject power post contingencies up until a system re-dispatch is invoked.

Congestion cost is typically spread across hundreds of hours in a year depending on the fluctuating economics and quantities of energy production facilities and demand resources [4]. Congestion relief has a diminishing return whereby the first MW increase in transmission capacity accrues the highest economic value while the last MW accrues the least. Sizing energy storage systems should necessarily optimize the trade-off between congestion relief benefits and storage system costs.
This paper investigates the use of energy storage systems to economically relieve congestion on key bottlenecks in the Great Britain (GB) transmission grid [5] including the strategic locations and sizes of storage facilities and their control systems that can unlock an increasing level of the grid’s inherent transfer capacity. This paper further compares the lifetime costs of the storage systems against comparable conventional wires solutions.

The paper provides a theoretical basis for optimizing the sites and sizes of energy storage that can increase the reliable transfer capacity across a transmission interface, flow gate, or boundary. It further provides a methodology to compare the lifetime economics of storage-based solutions against conventional solutions. Several publications on siting and sizing energy storage have focused on optimizing the economics of renewable variable energy resources [6-9] or system frequency response [10], while others [11-16] have focused on generalized optimization methods for alleviating grid constraints or spatial-temporal energy arbitrage. In contrast, the approach presented in this paper provides many advantages:

- Highly scalable to large power systems.
- Focuses on transmission grid security under all planning contingencies (P1–P7 [2]).
- Takes as input the familiar representation of the system in terms of a power flow model and the set of contingencies and monitored facilities without the need to pre-calculate transfer capacity limits.
- Can be performed by transmission planners by manipulating existing power flow and security analysis tools.
- Provides valuable locational insights that enable an iterative planning process using storage-only or hybrid solutions encompassing combinations of conventional wires solutions and storage solutions.

2. Energy Storage Siting Analysis Methodology

The siting analysis aims to find the best locations within a grid where storage systems can be most effective at reducing the lifetime cost of grid congestion while ensuring secure operation of the power system. The analysis is influenced by the grid structure (topology and equipment ratings), loading profile, renewable energy profile, and the critical contingency list.

The congestion cost of a transmission grid with a set of injection (generation and load) nodes denoted as i, a set of congested lines denoted as k, and a contingency list of equipment outages denoted as j, can be calculated using a security-constrained optimal power flow and can be expressed in a linearized format as:

$$Congestion\ Cost = \ MAX_j \{ \sum_k \mu_k \left(\sum_i \ h_{ki}.P_i + \ L_{kj}.F_j\right) \} \ )$$

Where,

Pre-outage power flow on line j is $F_j \ = \sum_i h_{ji} \ \ P_i$

μ_k is the marginal cost of congestion of line k

$L_{kj} = \frac{\partial F_k}{\partial F_j}$ is line the outage distribution factor, or, specifically, the change in power flow on line k due to outage of line j

$h_{ki} = \frac{\partial F_k}{\partial P_i}$ is the power transfer distribution factor, or, specifically, the change in power flow on line k due to injection at bus i

The sensitivity index of the system congestion cost to a power injection at bus i can be derived as:

$$\frac{\partial Congestion}{\partial P_i} = MAX_j \ \{\sum_k \mu_k \ (\ h_{ki} + L_{kj} \ .h_{ji} \ )\})$$

A variation on the formula directly above is to consider the probability of each contingency in lieu of the worst-case embodied by the MAX function. Another variation is to set μ_k as a function of the overload of the monitored line.

For technologies connected in a shunt configuration to a grid bus, such as generators, loads, and energy storage, the locations with the largest negative (or positive) sensitivity index are the most influential in reducing the congestion cost when the battery is operated in a discharge (or charge) mode. The analysis can either be repeated for each chronological hour or performed on a select set of snapshots of loading profiles. The optimal sites are ranked by sorting the annualized congestion cost sensitivities for each of the potential sites as calculated using the formula above, in ascending order, with the highest being the best site for locating an energy storage system. The above formulation does not require any optimization method to calculate. The marginal costs are relative and can be taken as uniform for all lines. They can also be skewed to reflect the level of line loading or, if available, the marginal congestion cost of each line.

3. Sizing Analysis Methodology

The objective of adding energy storage systems to relieve grid congestion is to allow the dispatcher to load the transmission grid, during normal operation, up to its N-0 limits, and for the storage to remain ready to offset any potential overloads on congested lines that may result after a contingency event.

If the flow on a path k is denoted by F_k^{post} during a post-contingency event and F_k^{pre} prior to the contingency event, and if the injection at bus i is denoted by P_i^{post} during post contingency and P_i^{pre} prior to the contingency event, then:

$$F_k^{post} = \sum\nolimits_i h_{ki} \,.\, P_i^{post} + \ L_{kj}.\sum\nolimits_i h_{ji} \,.\, P_i^{post}$$

and, the change in line k flow resulting from a line j outage is:

$$\Delta F_k^j \ = \ F_k^{post} - \ F_k^{pre} = \sum\nolimits_i h_{ki} \,.\, (P_i^{post} - P_i^{pre}) + \ L_{kj}.\sum\nolimits_i h_{ji} \,.\, P_i^{post}$$

The energy storage sizing problem can be formulated as a linear program (LP) – the aim of which is to minimize the largest increase in congestion cost resulting from all contingency events – as follows:

$$\min \left(\max_j \sum_k (\ \mu_k \,.\, \Delta F_k^j \ ) + \ \sum\nolimits_i \propto_i \left(P_i^{post} - P_i^{pre}\right) \right)$$

Subject to:

$P_i^{min} \leq \left(P_i^{post} - P_i^{pre}\right) \leq P_i^{max}$

for all buses i where energy storage is contemplated, where P_i^{max} and P_i^{min} are the discharge and charge power rating limits of a storage system at bus i (in part due to substation capacity limits).

$\sum_i P_i^{post} = 0$, to preserve the power balance in the post contingency state (optional).

$\propto_i$ is the marginal cost of power generation or storage at node i.

This is a general formulation and allows the grid planner to optimize the size of a single or a set of coordinated energy storage systems. It also allows balanced or unbalanced storage solution strategies, where a balanced strategy will require that the storage systems charge and discharge in a manner that has a zero net injection into the power system, and thus, avoid any interaction with the energy market even during a brief period after the occurrence of a rare contingency. The solution of the LP is very fast (seconds). The above formulation can be modified to consider reliability violations with a few additional constraints in the LP formulation.

4. Techno-Economic Analysis Methodology

A solution that includes an energy storage asset should be evaluated on the same basis as a conventional solution. However, there are differences between the attributes of the two categories of solutions, including the permitting duration, the expected life, the asset management strategy and costs, the operational risk, and the ability to provide additional services beyond the primary reliability function, which should be quantified and evaluated equitably.

The proposed economic analysis methodology considers the lifetime costs of each solution including initial capital, operations and maintenance, capacity augmentation, asset replacement and renewal, and asset retirement. The analysis considers the revenue requirements of each solution as a regulated asset, and thus, focuses on the cost to the utility customer. The evaluated cost can be adjusted up or down to account for additional value or revenue streams that a solution may provide.

The economic evaluation of the storage solutions as compared to the conventional T&D solutions requires the following:

- Lifetime modeling of the cost of each project from inception to retirement inclusive of project development activities and timeline, EPC (Engineering, Procurement, Construction), O&M (Operations and Maintenance), capacity management, replacement, disassembly, and recycling.
- Modeling of relevant utility's capital structure including debt and equity ratios, costs, and tax rate.
- Proper regulated-asset-base (RAB) accounting including treatment of asset depreciation.
- Useful asset life estimates: The conventional T&D solutions have an assumed book life of 40 to 60 years, while the energy storage technology has a typical useful calendar life of 10 to 15 years for lithium-ion technology and is further restricted by the usage profile and its impact on the life cycles.

The following methodology is adopted to compare the economics of the various solution alternatives:

- The initial installed capacity of the energy storage part of a solution is upsized to mitigate the anticipated capacity fading throughout the asset life. For a nominal 2% annual degradation of storage capacity [18], the installed storage MWh capacity can be upsized by 16% from the level required to address the system needs in order to have one augmentation at mid-life.
- A straight-line depreciation of each asset is adopted for book accounting and tax purposes. The tax depreciation methodology can vary depending on applicable rules. In the U.S., accelerated depreciation is used for tax depreciation.
- Due to the differences in asset life between the conventional asset (40–60 years) and the storage asset (10–15 years), the analysis is carried out over a 45-year horizon, and multiple battery investment/replacement cycles are considered. Two approaches are considered for the comparative analysis; the first calculates the present value of each solution cost over the 45-

year horizon, while the second focuses on the first life of the storage system (e.g., 15 years) and calculates the levelized real cost of the conventional solution over that period of time utilizing a real economic carrying cost taking into account the utility's weighted average cost of capital and the inflation rate.

- The present value of the revenue requirement for each solution is calculated.
- The ratio of a storage solution's revenue requirements to that of the conventional solution is taken as the key metric of evaluation. When the ratio is below 1, the storage solution is deemed less expensive for the ratepayers than the conventional solution.

5. Case Study: Unlocking Boundary Limitations of the UK Transmission Grid

5.1 System Boundaries

The National Electricity Transmission System (NETS) in Great Britain uses the concept of boundary to assess the capability of the network to transfer power from areas of generation to areas of demand. A boundary splits the network into two parts, crossing critical circuit paths that carry power between different areas where power flow constraints may be encountered. The GB network has over 30 defined boundaries [5] (see **Error! Reference source not found.**).

This paper examines the use of energy storage to unlock the transfer capacity of a key congested boundary between the SP Transmission Ltd. in Scotland and the National Grid Electricity Transmission (NGET) systems in England. The economic cost of this congested interface is high and increasing as wind resources in Scotland are routinely curtailed and generation resources in England are ramped instead. Scotland contains significantly more installed generation capacity than demand, increasingly from wind farms. To enable the energy to flow reliably to the demand centers in England, the study also examined Boundary 7a, which bisects England south of Teesside and into the Mersey Ring area. These two boundaries are limited by multiple contingencies.

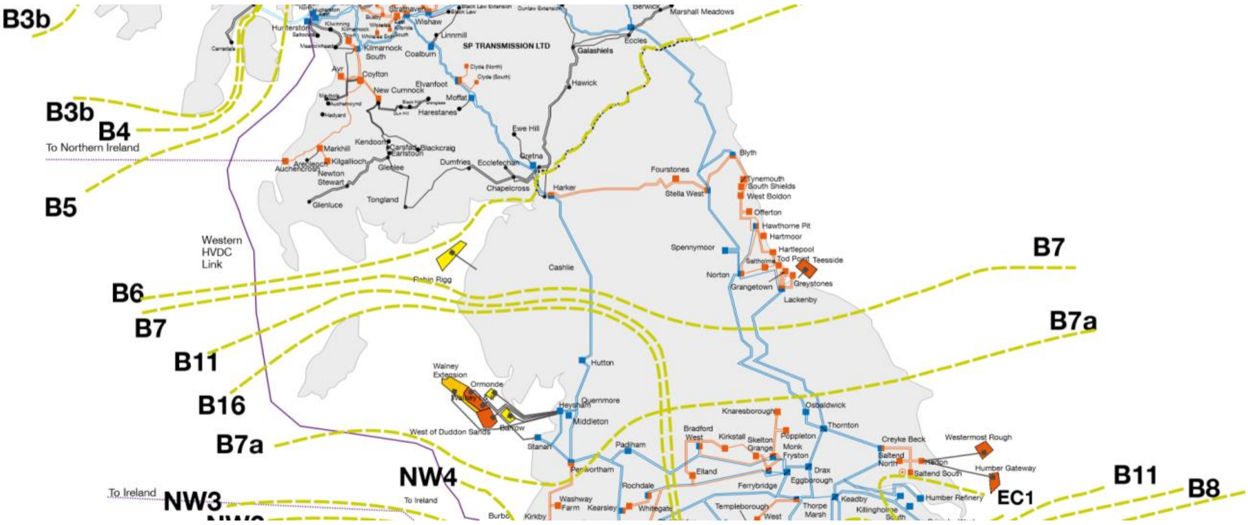

Figure 1. Geographic location of Boundary B6 and B7a, and circuits they cut across

Boundary B6 cuts across two 400-kV double circuits and 132-kV circuits, while B7a cuts across three 400-kV double circuits and 275-kV circuits. Both boundaries also cut across one HVDC circuit.

Table 1 below shows the sum of circuit ratings comprising each boundary, base case flow limits, and contingent flow limits. Additionally, an indicative level of the desired boundary capability is shown.

Table 1. Boundary Limits

Boundary	Sum of Circuits Rating (MVA)	N-0 Limit (MW)	Contingent Limit (MW)	Desired Boundary Flow Limit (MW)
SP Transmission Ltd. to NGET (B6)	12,629	10,723	5,700	9,358
Upper North of England (B7a)	19,596	12,482	8,700	9,165

Due to the overloads on B6 boundary facilities, which range from 120% to 230% of their Rate B limits post contingency, B6 is limited to 5,700 MW out of its 12,629-MW thermal rating, or a maximum utilization of 45%, while B7a is limited to 8,700 MW out of its 19,596-MW thermal rating, or a maximum utilization of 44%. To accommodate all the installed wind resources in Scotland as of 2018 would require a solution that could increase the transfer limits across B6 to 9,358 MW (or 74% utilization) and across B7a to 9,165 MW or (47% utilization).

5.2 Unlocking B6/B7a Boundary Capacity Using Conventional Solutions

Several conventional solutions consisting of new transmission lines, upgrades of existing lines, new substations, transformers, series reactors, and reactive compensation were designed to unlock the transmission capacity across B6/B7a boundaries.

Table 2 summarizes three conventional solutions. It also shows the level of reliable transfer that can be achieved and the estimated cost of the requisite upgrades. The conventional solutions increase the transfer limits by 3.6 GW to reach 9.3 GW at a cost range of £337–1,022M. The constructability of these solutions is not addressed in this paper, but suffice to say, some might require a lengthy and contentious permitting process.

Table 2. Conventional Solutions of B6/B7a

Solution	Solution Components	Contingent Boundary Flow Limit (MW)	Total Cost £M
Conventional A	• A new 400kV line and substation. • Series Reactor. • Reactive support. • Re-conductor 400kV circuit.	9,276	337
Conventional B	• Two new 400kV lines. • Two new 275kV lines. • Two GSUs (400/275 kV) • Reactive Support. • Series Reactor.	9,276	1,022
Conventional C	• Two new 400kV lines. • Conversion of a 275kV line to 400kV. • Loop in a 400kV line.	9,276	943

5.3 Unlocking B6/B7a Boundary Capacity Using Hybrid Solutions

Hybrid solutions are developed to address the thermal and voltage violations of limiting contingencies on boundary B6 and B7a. Hybrid solutions involve a combination of conventional wires solutions and battery energy storage to alleviate all the system violations under the considered contingencies. The conventional wires parts of the solutions are chosen to reduce the size of energy storage requirements and to reduce the total cost of the project. The hybrid solutions are organized into four categories (A, B.1, B.2, and C as shown in Figure 2. Each solution category is optimized for three transfer levels (9.3 GW, 8.4 GW, and 7.4 GW). Solution A is additionally optimized for a transfer limit of 6.8 GW. The size of the energy storage within the hybrid solutions increases with the level of increase in the boundary transfer limits. At a transfer limit of 6.8 GW (or an increase of 1.1 GW above the existing 5.7-GW limit), the energy storage size is modest at 125 MW with a total solution cost estimated at £73M. However, as the desired transfer limit is increased, the energy storage system size increases rapidly as shown in **Error! Reference source not found.**. The cost calculations assume the storage system to have an energy capacity of 30 minutes.

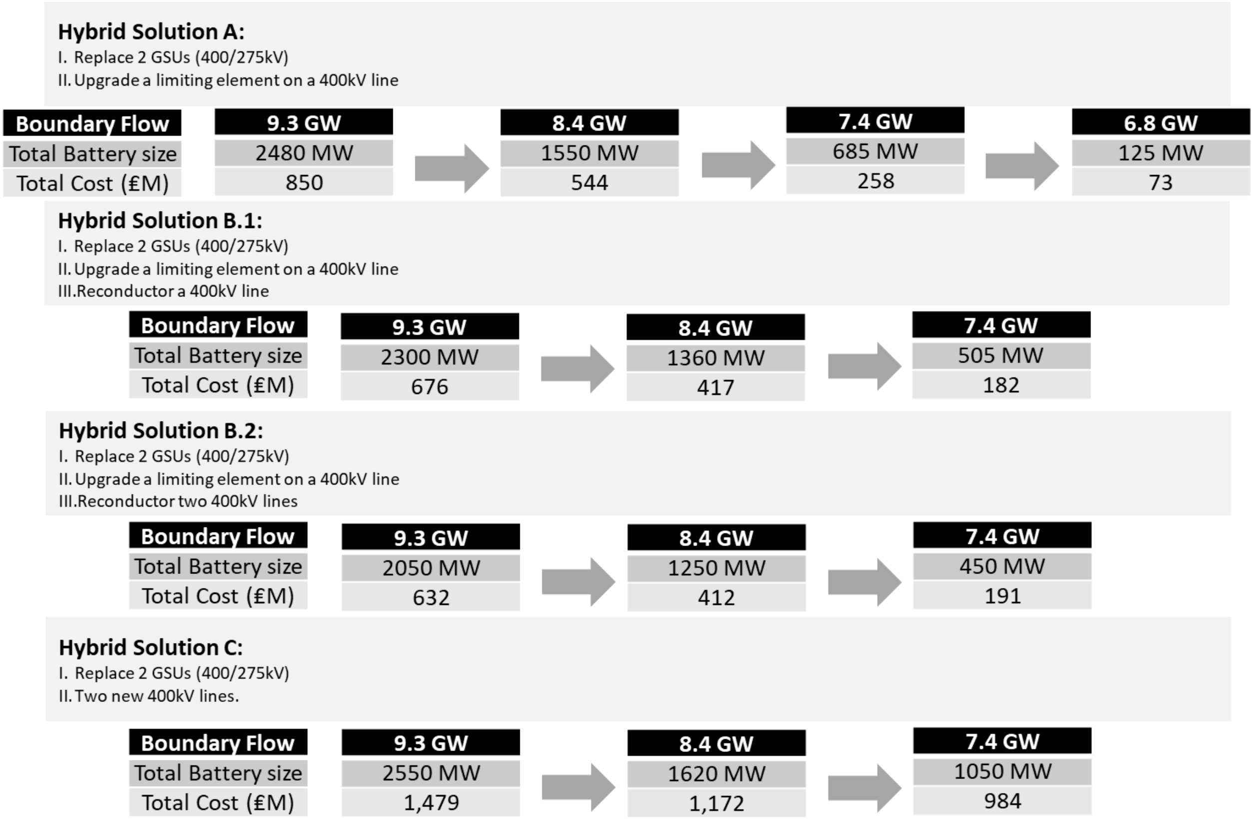

Figure 2: Hybrid Solutions to Unlock Capacity of B6/B7a Boundaries

Table 3: Hybrid Solution Battery Size Results

B6/B7a Transfer Limit	**Incremental Increase in Boundary Limit Above the 5.7-GW limit**	**Battery Size (MW) (Lowest Cost Solution)**	**Hybrid Solution Cost (£M)**	**Battery Size to Incremental Transfer Ratio**
9.3 GW	3.6 GW	2050	632	57%
8.4 GW	2.7 GW	1250	412	46%
7.4 GW	1.7 GW	505	182	30%
6.8 GW	1.1 GW	125	73	11%

The relative size between the storage MW rating and the resultant increase in the boundary transfer limit ranges from 11% at the low end to 57% at the high end.

The selection of the energy capacity should be dictated by and/or coordinated with the wholesale energy market, and it will reflect the flexibility in re-dispatching the generation portfolio post contingency (i.e., transition to an out-of-merit dispatch to mitigate the transmission overloads until the contingency is remedied or the load level or generation level from wind and solar resources reduces).

5.4 Techno-Economic Comparative Analysis of the Conventional and Hybrid Solutions

The lifetime costs of each conventional and hybrid solution are modeled for a 45-year horizon, taking into account the capital and O&M costs and adhering to the proper asset-management strategy of the storage systems including initial capacity upsizing, capacity augmentation, inverter replacements, disposal and recycling, and asset replacements. The lifetime costs of each solution are modeled as a regulated asset, and the present value of the lifetime costs, as well as the revenue requirements that will be charged to the utility rate payers, are quantified. The results of the lifetime cost comparisons are captured in Error! Reference source not found.**,** and a relative cost ratio (%) between hybrid and conventional solutions is displayed.

Table 4: Lifetime Cost Estimation of Conventional and Hybrid Solutions

<table>
<tr><td colspan="4" rowspan="5">Initial Capital Cost, Annual Operating Costs, Lifetime Project Costs, and Customer Cash Flows are shown for each of the considered solutions.
Customer Cost Ratios for ESS to Conventional Solutions are cross-tabulated for all considered solutions.
All currency in millions of pounds (£M)</td><td></td><td>Conv. Solution A</td><td>Conv. Solution B</td><td>Conv. Solution C</td></tr>
<tr><td>Capital Cost (£M)</td><td>322</td><td>1,016</td><td>873</td></tr>
<tr><td>Annual OPEX (£M)</td><td>4.8</td><td>15.2</td><td>13.1</td></tr>
<tr><td>Lifetime Cost – PV (£M)</td><td>389.8</td><td>1,230</td><td>1,056.9</td></tr>
<tr><td>Customer Cash Flows – PV(£M)</td><td>426.3</td><td>1,345.1</td><td>1,155.8</td></tr>
<tr><td>Hybrid Solutions</td><td>Total Initial Capital Cost (£M)</td><td>Annual OPEX (£M)</td><td>Lifetime Cost – PV (£M)</td><td>Customer Cash Flows – PV (£M)</td><td colspan="3">Customer Cost Ratio (Storage Cost / Conv. Cost)</td></tr>
<tr><td>Hybrid A</td><td>1,048</td><td>32.5</td><td>1,836.6</td><td>2,136</td><td>501%</td><td>159%</td><td>185%</td></tr>
<tr><td>Hybrid B.1</td><td>988</td><td>30.4</td><td>1,723.1</td><td>2,003</td><td>470%</td><td>151%</td><td>173%</td></tr>
<tr><td>Hybrid B.2</td><td>913</td><td>27.6</td><td>1,575.1</td><td>1,828</td><td>429%</td><td>136%</td><td>158%</td></tr>
<tr><td>Hybrid C</td><td>1,681</td><td>42.4</td><td>2,617.7</td><td>2,994</td><td>702%</td><td>223%</td><td>259%</td></tr>
<tr><td colspan="8">Partial Mitigation</td></tr>
<tr><td>Boundary Capacity: 7.4 GW</td><td>273.6</td><td>7.16</td><td>435</td><td>499.5</td><td></td><td></td><td>48%</td></tr>
<tr><td>Boundary Capacity: 8.4 GW</td><td>605.6</td><td>17.72</td><td>1,025.6</td><td>1,187.7</td><td></td><td></td><td>103%</td></tr>
</table>

The key findings of the analysis are summarized below and show that storage-based hybrid solutions are competitive at lower levels of capacity expansion and not as competitive at high levels of capacity expansion:

Increasing the boundary capacity to 7.4 GW using hybrid solution B.2 is found to be *two times more cost-effective* than conventional solution C.

Increasing the boundary capacity to 8.4 GW using hybrid solution B.2 is found to be comparable to conventional solution C.

5.5 Optimizing the Level of Transfer Limit (a Partial Congestion Mitigation Strategy)

The study has identified multiple conventional and hybrid solutions at each level of increase in the transfer limit across boundaries B6 and B7a. The cost of the solutions increases geometrically with the level of increase in the transfer limits. Therefore, a prudent selection of the desired level of increase in the boundary transfer limit and the selection of the solution technology is key to the economic success of a project.

A proper benefit-cost analysis is proposed to determine the optimal level of capacity increase. A systematic approach to quantifying the benefit-cost trade-off and determining an optimal level of transfer capacity increase is presented here.

The constraints of B6/B7a boundaries are mitigated through curtailments of wind resources in Scotland and an out-of-merit dispatch of system resources. The payments to wind generators as compensation for these curtailments have been increasing steadily since 2010 as shown in Table 5 [19]. These payments have reached £141M in fiscal year 2018/19.

Table 5: Annual Payments to Wind Farms

(in £M)	**2010/11**	**2011/12**	**2012/13**	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**2018/19**
Payments to wind-powered generation	0.2	34.1	7.6	49.7	65.3	96.8	83.2	108.0	140.7

The published market reports [17, 20] show the monthly volumes and costs of boundary constraints. For solutions that aim to mitigate the constraints completely, the value of these solutions is provided by the constraint costs. However, for solutions that aim to optimize the level of constraint mitigation, a granular analysis is required to translate the monthly or daily constraint costs and volumes to corresponding hourly or half-hourly values. The granular resolution will enable the valuation of unlocking a defined level of boundary capacity (in MW).

Due to the unavailability of the granular constraint information, wind generation curtailments in the SP Transmission Ltd. region (obtained from ref.uk.org) for wind farms with greater than 1 MW of capacity are collected and are assumed to correlate in pattern to the boundary B6 constraint costs and volumes. The collected half-hour wind curtailment data is then organized as shown in Figure 3.

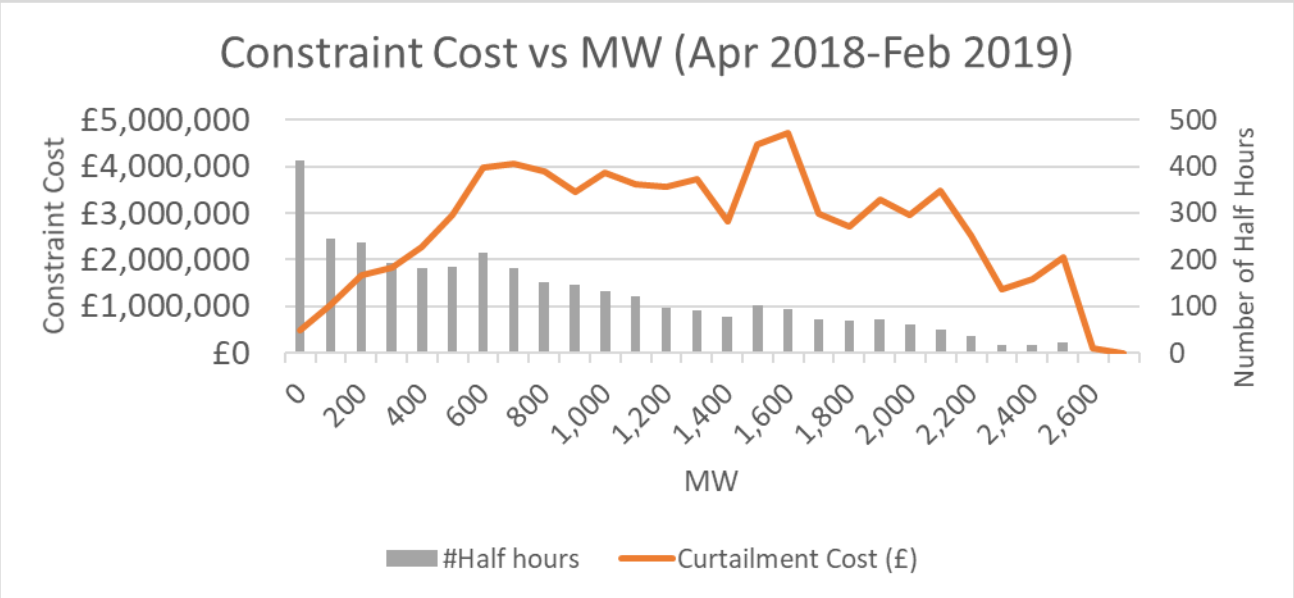

Figure 3. Constraint Cost and Duration for Various MW Layers of the Boundary Constraint

The boundary experiences constraints during 3,278 half-hours, and they cost £75.6M during the period from April 2018 through February 2019. During 412 half-hours, the boundary experiences constraints below 100 MW, and the system would have dispatched 8,579 MWh incremental flow across the boundary had it not been constrained. For all layers of boundary capacity (MW) constraints, the system would have dispatched a total of 1,350 GWh incremental flow had the boundary not been constrained. The analysis reveals that the maximum amount of boundary constraint for the year was 2,800 MW. Adding this to the boundary transfer capacity of 5,700 MW shows that the maximum boundary capacity that is economically useful from the system perspective is 8,500 MW for the fiscal year 2018/2019. This limit will increase with the additions of wind resources in Scotland.

The first 100 MW of boundary capacity constraint is binding during all the constraint hours in the year, while the second layer from 100 to 200 MW binds during relatively fewer hours and so on. Therefore, the first 100 MW of constraint mitigation is the most valuable, while the second layer and beyond will experience a diminishing value as shown in Figure 4.

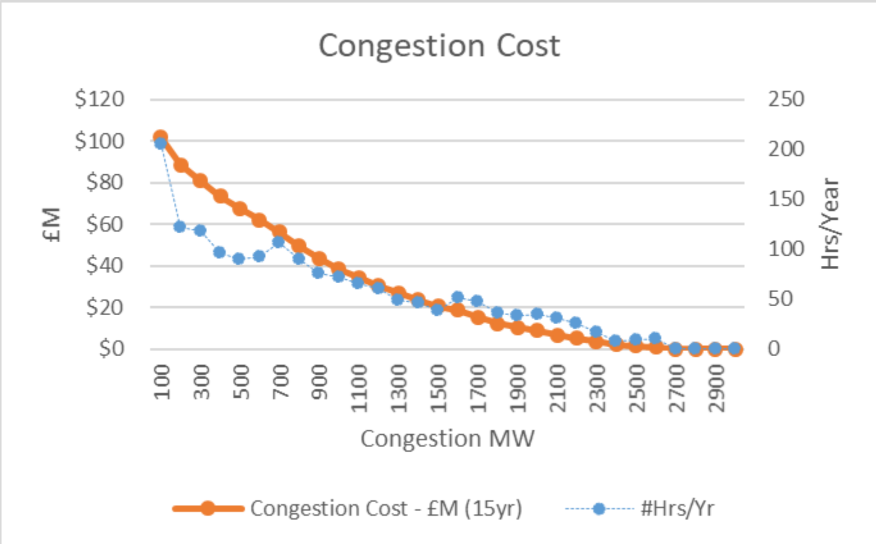

Figure 4: Constraint Cost and Duration for Each Layer of Overloaded Constraint Capacity

6. Optimizing the Partial Constraint Mitigation

Using high-level assumptions about the battery cost, the size of battery required to mitigate each layer of constraints, and assuming a 30-minute battery capacity, Figure 5 compares the cost of the battery to the benefit of the constraint mitigation (the benefit is measured by the 15-year present value of the cumulative congestion cost reduction). Figure 6 shows the ratio of the two costs in a benefit-cost ratio. The optimal size of partial mitigation is 2,200 MW (crossover point between cost and benefit). This level will increase if the battery cost decreases and will decrease if the battery cost increases.

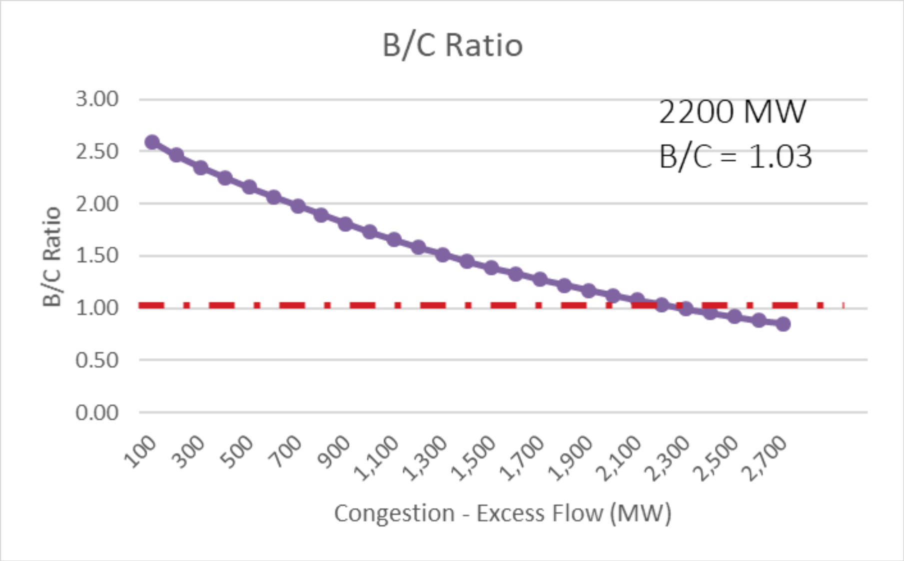

Figure 5: Benefit-Cost Ratio of Unlocking Various Levels of Constraint Capacity

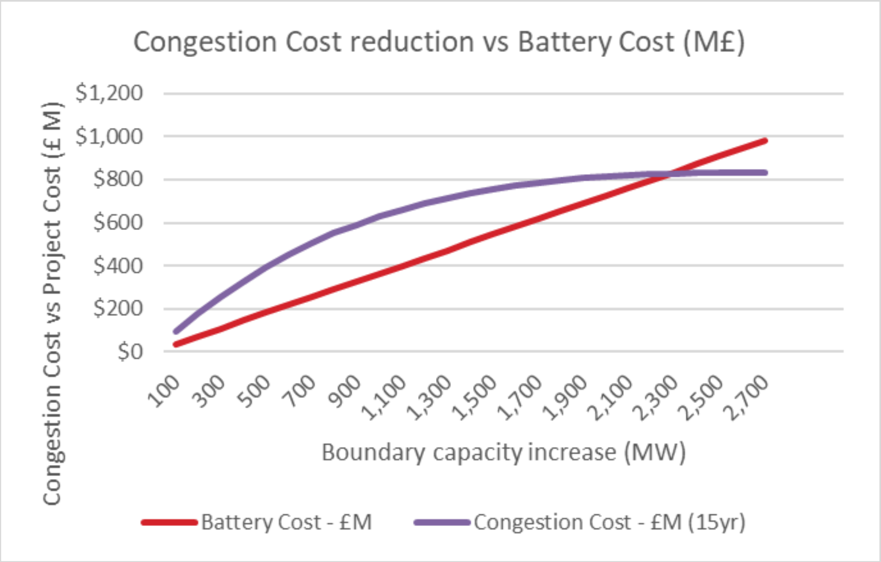

Figure 6: Comparison of Constraint Cost Against Battery Solution Cost at Various Levels of Capacity Expansion

The partial mitigation analysis reveals that it is cost-effective to improve the boundary capacity by 2.2 GW.

However, selecting a threshold for the benefit-to-cost ratio of 1.25 to provide additional economic certainty, the boundary capacity increase of 1.7 GW is optimal. Hybrid solution B.2 is selected to increase B6 boundary capacity to an optimal transfer level of 7.4 GW. It requires a 450-MW battery.

The hybrid solution is compared against conventional solution C. However, the conventional solution completely mitigates the constraint up to 9.3 GW. To have an equitable comparison between the two solutions, the portion of congestion cost savings forgone by the hybrid solution for half-hourly constraint volumes greater than 1.7 GW is calculated, and the additional value of the conventional solution is credited against the conventional solution cost.

- Additional congestion cost savings foregone by hybrid solution annually: £4.2M
- Present value of congestion cost savings forgone by the hybrid solution (45 yrs): £85.2M
- The present value of additional congestion cost savings is credited to the conventional solution cost. Initial cost of conventional solution C = £787.8M

The analysis shows the hybrid solution's lifetime cost to be only 48% of the comparable conventional solution.

7. Conclusions

Energy storage was found to be technically feasible, and in a few cases economically superior. The evaluations also demonstrated that energy storage solutions become more viable when the permitting process of conventional wires solutions turns lengthy and when the storage technology cost reduction accelerates. In short, energy storage is a valuable tool in the planning process, and its importance will grow over time. The key findings of this study are as follows:

- Energy storage technology is technically feasible to increase the transfer limits of the transmission grid boundaries.
- Energy storage-based solutions are economically competitive at lower levels of capacity expansion and not as competitive at high levels of capacity expansion when compared to conventional solutions.
- Optimizing the level of transmission transfer capacity expansion is critical to the economic feasibility of energy storage solutions. This requires a careful analysis of historical and future projections of constraint costs and a proper benefit-cost analysis.
- The optimal siting and sizing of storage solutions is a fundamental requirement for this type of analysis.
- Energy storage solutions become competitive, even at high levels of boundary capacity expansion, if the conventional solutions take a long time to permit or if the energy storage cost reduction roadmap accelerates.

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