March 2024

Interconnector Analysis Report

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Contents

1. Introduction

This analysis outlines the socio-economic benefits of interconnection for consumers, generators and interconnector developers under a range of scenarios. Rather than assessing actual projects it evaluates the benefit from hypothetical interconnectors.

The analysis can provide a market and network assessment of the optimal mix of interconnection capacity. It evaluates the overall benefit to society by considering socio-economic welfare (SEW), as well as constraint costs, capital expenditure (Capex) and environmental impacts. The analysis does not assess the viability of current or future interconnector projects; the final insights are based on assessing a range of theoretical interconnector options.

2. Summary of results

Interconnectors are cables that enable the flow of electricity from one electricity or gas market to another, different market. Increased levels of interconnection between Great Britain and the markets we connect with can provide benefits in several ways.

Interconnectors can supply additional volumes of energy when needed, helping to balance supply and demand in a flexible way and often at short notice. New interconnectors using Voltage Source Converter (VSC) technology have the potential to provide technical services, such as voltage regulation and frequency response that will be important to operating and balancing Great Britain's transmission system, helping keep the network safe and secure as more renewable generation is connected. Conversely, interconnectors can also create additional operational challenges and lead to an increase in system operation costs.

Additional interconnection to and from Great Britain can provide economic and environmental benefits for both Great Britain and Europe and will make an important contribution to achieving net zero by 2050. The high level of installed renewable generation that is critical to achieving net zero means that supply will often exceed demand and interconnectors enable this excess power to be exported to the continent.

As we move towards net zero it is important to develop both the onshore and offshore networks holistically and interconnectors will have an important role to play. At present, interconnectors are used to connect Great Britain's transmission system directly to another market, but in the future offshore windfarms or other infrastructure may connect to an interconnector without bringing this power onshore to the Great Britain transmission system. These are called Offshore Hybrid Assets (OHAs). Centralised strategic network planning will ensure that the location of interconnectors and OHAs will create maximum value for Great Britain.

The location of new interconnection is important. If interconnectors connect to Great Britain's network where there is network congestion, then the interconnector may increase congestion further. Alternatively, interconnectors may help reduce network congestion if located at other parts of the network.

The impact of additional interconnection on carbon emissions is complex. They may increase or decrease when an interconnector is added, depending on the impact on Renewable Energy Supplies (RES) and thermal generation. While the addition of an interconnector nearly always results in a reduction in RES curtailment, it may also result in an increase in thermal generation output.

3. Interconnection theory

Electricity interconnectors allow the transfer of electricity between markets. Currently Great Britain has approximately 10 GW of interconnection with other European markets; however, our *2023 Future Energy Scenarios*[1] (FES) see an increase to between 16 GW and 27 GW by 2050 depending on which scenario is considered.

Increases in interconnection can deliver benefits to both industry and consumers:

- **Greater security of supply** – both markets can access increased levels of generation to secure their energy needs.

- **Greater access to renewable energy** – increased access to intermittent renewable generation, consequently displacing domestic non-renewable generation.

- **Increased competition** – increased access to cheaper generation and more consumers leads to increased competition allowing some participants in both markets to benefit financially. These benefits are measured as socio-economic welfare (SEW).

SEW is a common indicator in cost-benefit analysis of projects of public interest. It captures the overall benefit, in monetary terms, to society from a given course of action. It is an aggregate of multiple parties' benefits – so some groups within society may lose money because of the option taken. In this analysis, SEW captures the financial benefits and detriments of market participants due to increased interconnection. The increase in SEW must also be balanced against the capital costs of delivering the increased interconnection capacity, any associated reinforcement costs, and any carbon-emission impacts. As capacity is increased between two suitable markets and SEW delivered, prices between the two markets begin to converge until ultimately further interconnection brings no benefit.

The three elements of SEW are:

- **Consumer Welfare** – Increased consumer welfare due to reduced prices in the higher priced market, as suppliers have increased access to cheap renewable generation. Reduced consumer welfare due to increased prices for consumers in the cheaper market, as they now share their access to cheaper generation with more consumers.
- **Producer Welfare** – Increased producer welfare due to increased revenue for generators in the lower priced market, as generators can now access more customers. Reduced producer welfare due to reduced revenue for generators in the higher priced market, as they are now competing against cheaper overseas generation.
- **Interconnector Welfare** – Revenue for the interconnector business generated from selling capacity across the interconnector.

[1] A description of the four 2023 Future Energy Scenarios is available at: https://www.nationalgrideso.com/document/283101/download

4. Methodology

This section provides a high-level overview of the methodology used within the interconnector analysis. The iterative process continues to focus on socio-economic welfare (SEW), capital costs and reinforcement costs, but also includes an assessment of any changes in carbon emissions due to the addition of increased interconnection. The optimal paths are based on SEW for Great Britain and the connecting country only. This makes the direct welfare benefits of the interconnector more transparent and avoids any SEW generated by flows between other countries. We have continued to use the recommendations from this year's *Beyond 2030 Report* as the baseline network reinforcement assumptions for the interconnector analysis: this provides greater consistency between the two sets of results. We have continued to produce four optimal interconnection development paths: one for each future energy scenario.

Figure 1 provides a high-level overview of the iterative process.

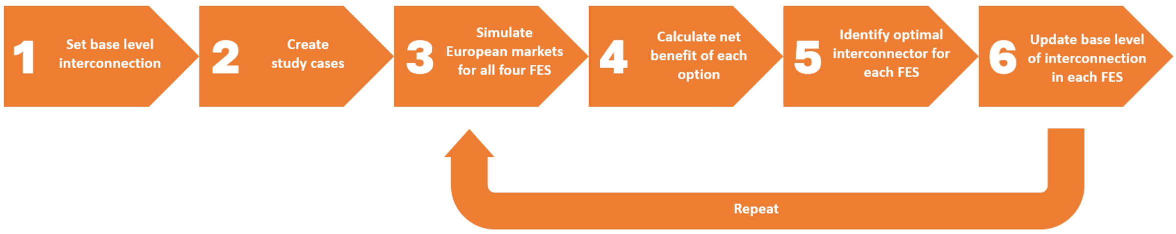

Figure 1: Iterative process for interconnector optimisation

The following section describes the iterative steps shown in Figure 1 in more detail.

Step 1 - Set base level of interconnection

The base level of interconnection is the total capacity Great Britain has with each of the seven studied markets at the start of the iteration. This year, the base level of interconnection included all projects currently operational and those with Cap and Floor Window 1 and 2 approvals.

Step 2 - Create study cases

To test the effect of additional capacity, 1.5 GW of interconnection was added in each of the European markets (i.e. to each of the seven European connecting countries) to the base level of interconnection. For each country's additional interconnector, we considered a range of Great Britain's connection zones. We studied 22 cases, with different combinations of connecting country and Great Britain's connection zone. The study cases are shown in Table 1. Additional interconnection is modelled to connect in 2031, 2033 and 2036, to understand the effects of varying commissioning dates on SEW and attributable constraint costs.

Step 3 - Simulate European markets

We ran 22 study cases for each of the four 2023 FES scenarios for all European countries in our BID3 economic dispatch optimisation tool then calculated SEW and constraint costs. The tool can simulate all European power markets simultaneously from the bottom up, i.e. it can model individual power stations and balance supply and demand on an hourly basis. We ran the model for the years 2030, 2035, 2040 and 2043, interpolated for the years in between and extrapolated for any years after 2043, with an assumed 25-year life expectancy for the project.

At the first stage of the process, a dispatch (or unconstrained run) is undertaken so that supply meets demand at each point in time, assuming the transmission network can send power wherever it is needed. Secondly, a re-dispatch (or constrained run) models constraints on the network, where generation is restricted in some areas of the country based on the capability of the network in that region, and generation is increased elsewhere to balance supply and demand. This is performed at minimum cost, and BID3 models this activity in the re-dispatch run.

Step 4 - Calculate net benefit of each potential interconnector

We used the formula PV = SEW - CAPEX – Constraint Costs for each option of country and Great Britain connection zone and connecting year for each scenario, where:

- PV = the result in present value terms. As costs are incurred across a range of years, discounting is employed to standardise each cost in present value.
- SEW = socio-economic welfare.
- CAPEX = capital costs for interconnector cable and converter station.
- Constraint costs = the costs incurred in ensuring all boundary constraints are met.

The cost of carbon is accounted for in the welfare calculation, with a higher carbon cost leading to reduced revenue for producers. Each tonne of carbon emitted by thermal power plants has been valued according to the central series price published by the Department for Energy Security and Net Zero.[2]

Any additional carbon emissions incurred due to activity within the Balancing Mechanism, for example curtailing wind generation in favour of activating thermal power plants, are also valued at the central series price set by the Department for Energy Security and Net Zero.

Step 5 - Identify optimal interconnector solution for each FES scenario

For each FES we identified which option has the highest PV across three connection dates (interconnectors commissioning in 2031, 2033 and 2036).

Step 6 - Update base level of interconnection in each FES scenario

We add the optimal solution to the base level of interconnection for each FES scenario and repeat steps 3 to 6.

The 22 study cases are shown in Table 1. Additional interconnection is modelled to connect in 2031, 2033 and 2036, to include the effect of varying commissioning dates on SEW and constraint costs.

In theory, the process for each FES finishes when it is deemed to have ‘converged’, that is when the ‘none’ (the base case, with no additional interconnection) is the option with the highest present value. This is discussed further in the outcome section.

[2] https://www.gov.uk/government/publications/valuing-greenhouse-gas-emissions-in-policy-appraisal/valuation-of-greenhouse-gas-emissions-for-policy-appraisal-and-evaluation#annex-1-carbon-values-in-2020-prices-per-tonne-of-co2

Code	Connecting country	GB connection zone
	Base	None
A	Belgium	5
B	Belgium	6
C	Belgium	7
D	Denmark	2
E	Denmark	3
F	Denmark	5
G	France	5
H	France	6
I	France	7
J	Germany	5
K	Germany	7
L	Germany	8
M	Ireland	1
N	Ireland	2
O	Ireland	3
P	Ireland	4
Q	Netherlands	5
R	Netherlands	7
S	Netherlands	8
T	Norway	1
U	Norway	2
V	Norway	3

Table 1: Study cases, showing interconnector connecting country and Great Britain connection zone.

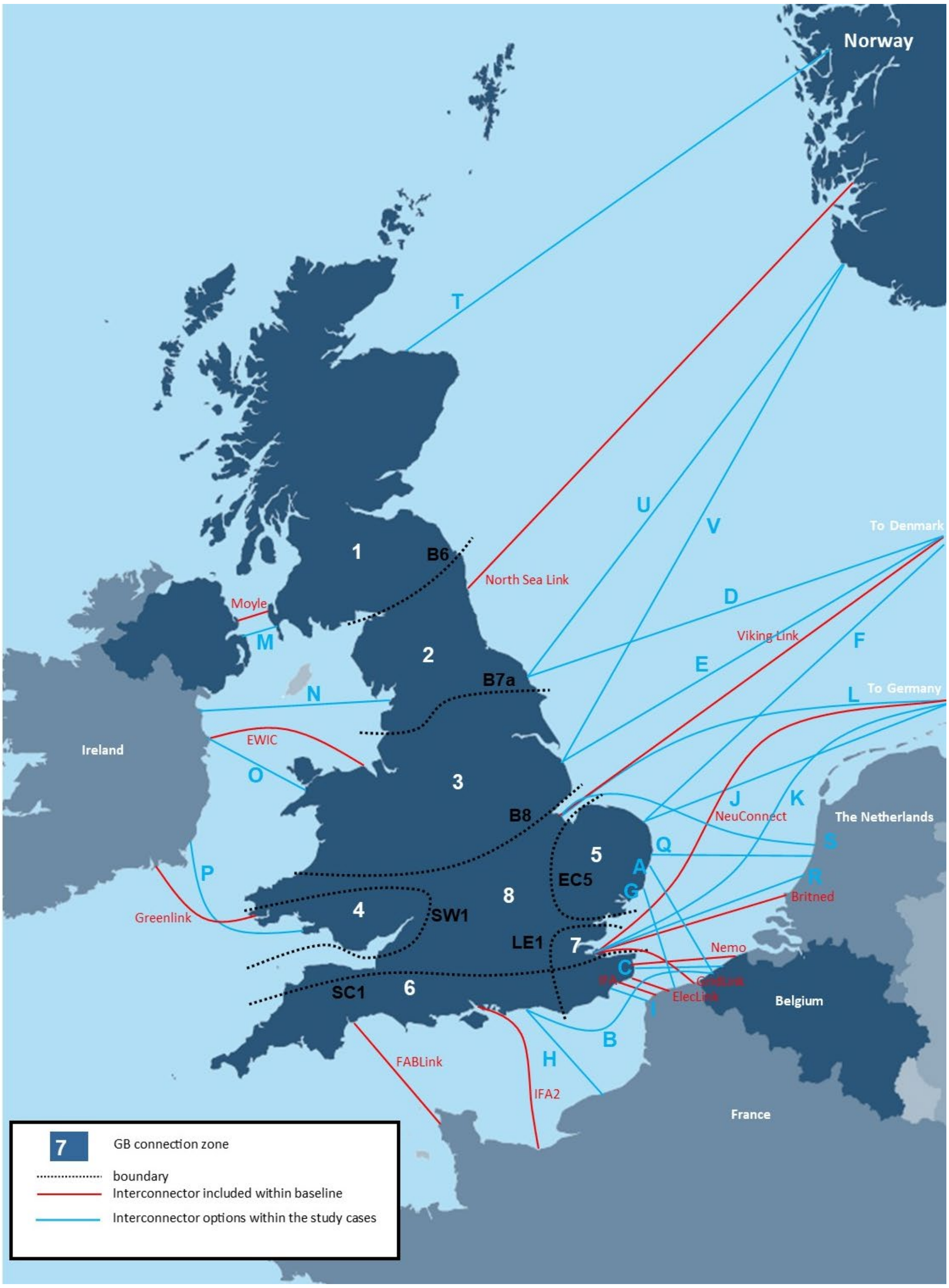

Figure 2: Map showing the 22 interconnector study cases and their GB connection zone and connecting country.

5. Estimation of interconnection construction costs

The cost of building interconnection capacity varies significantly between different projects, with key drivers including converter technology, cable length and capacity. The capital costs were derived from a publicly available ACER (Agency for the Cooperation of Energy Regulators) document[3], based on surveys carried out on European projects. Costs were included in 2023 prices and benchmarked against a range of interconnector cost data in the public domain. Whilst there was considerable variation across projects, the ACER costs provide a reasonable average.

Outcome

This year we have not provided a figure for the optimal level of reinforcement for each Future Energy Scenario (FES). The methodology only considers socio-economic welfare (SEW), Great Britain constraint costs, interconnector Capital expenditure (Capex) costs and impact on carbon emissions in calculating Net Present Value (NPV). The model identifies high levels of benefit in all four scenarios, even after ten iterations of the model, hence in theory we could have continued to run the model for further iterations. However, this would have resulted in unrealistically high levels of interconnection to Great Britain. The results would not have reflected the potential impact on system operability; hence the model was limited to ten iterations.

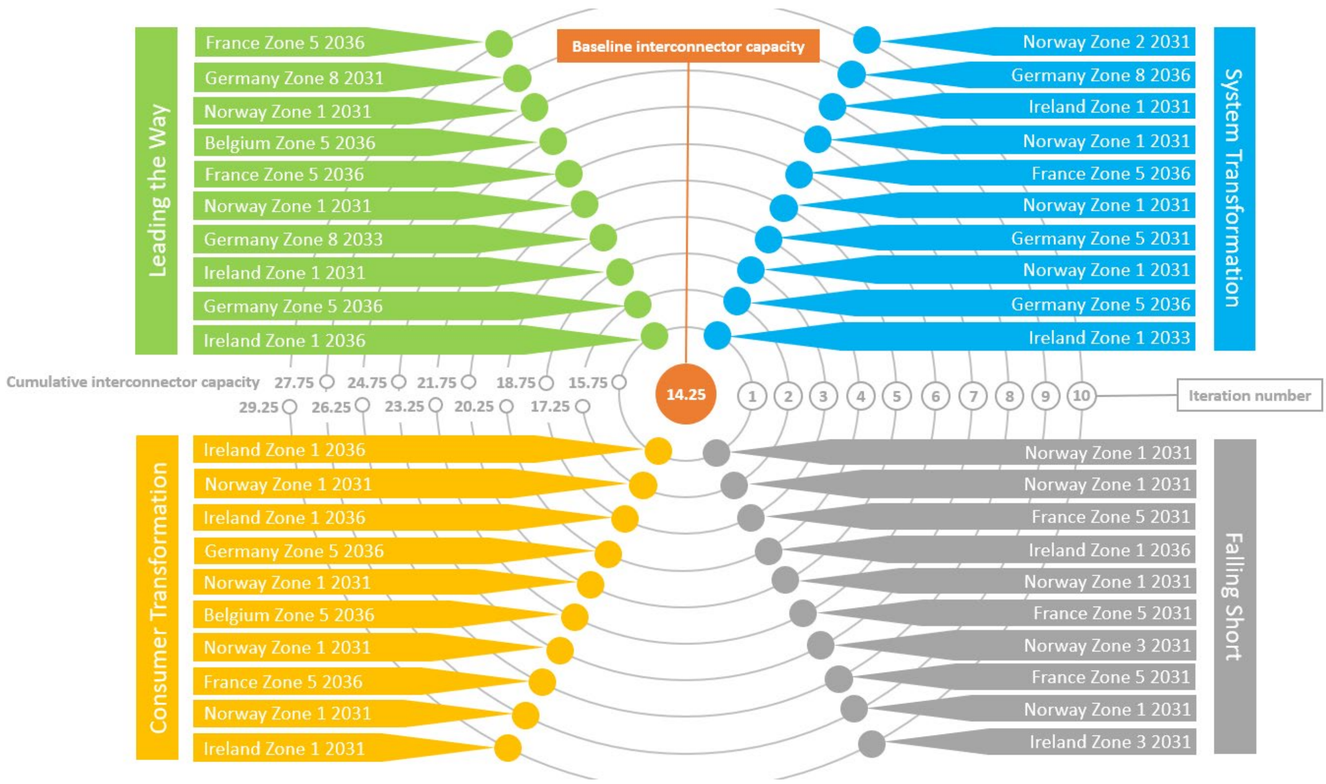

Figure 3: Optmal interconnection paths for each FES

Figure 3 shows the optimal interconnection paths for each FES scenario, which is the winning study case from each iteration that produced the highest NPV. These options provide the most benefit to Great Britain and the connecting country. As stated previously, the analysis does not produce the optimal total level of interconnection for each FES. There were still positive levels of NPV in all four

[3] https://www.acer.europa.eu/sites/default/files/documents/Reports/UIC_report_2023.pdf

FES scenarios after ten iterations, suggesting that in theory even higher levels of interconnection could be connected to Great Britain. This would be unrealistic for several reasons. Firstly, the results would not have reflected the potential impact on system operability. Having levels of interconnector capacity higher than that after the tenth iteration may produce challenges in operating Great Britain's system. Secondly, extending the paths beyond the tenth iteration may have resulted in levels of interconnection to certain European connecting countries that is not credible. For example, the levels of interconnection by iteration 10 to France and Norway may already be excessive.

The following analysis is in nine parts:

- Optimal interconnection paths
- Net Present Value of interconnection
- Import and export flows
- Regional analysis
- Offshore Hybrid Assets
- System Operability
- Environmental analysis
- Renewable Energy Supplies (RES) Integration
- Iteration deep dive into environmental and RES integration

Optimal interconnection paths

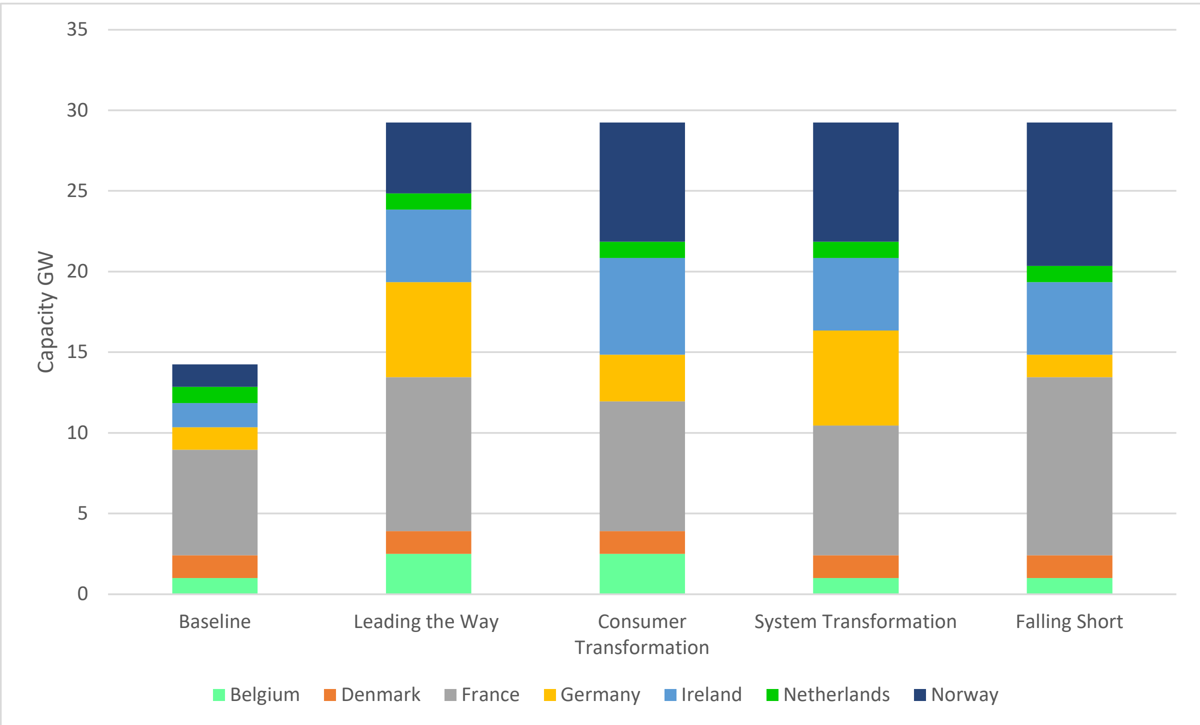

Figure 4: Total interconnection capacity by country for each FES and baseline capacity

Figure 4 shows the interconnection capacity for each FES scenario, broken down by connecting country after ten iterations. It shows the variations in interconnection capacity to different connecting countries across the scenarios.

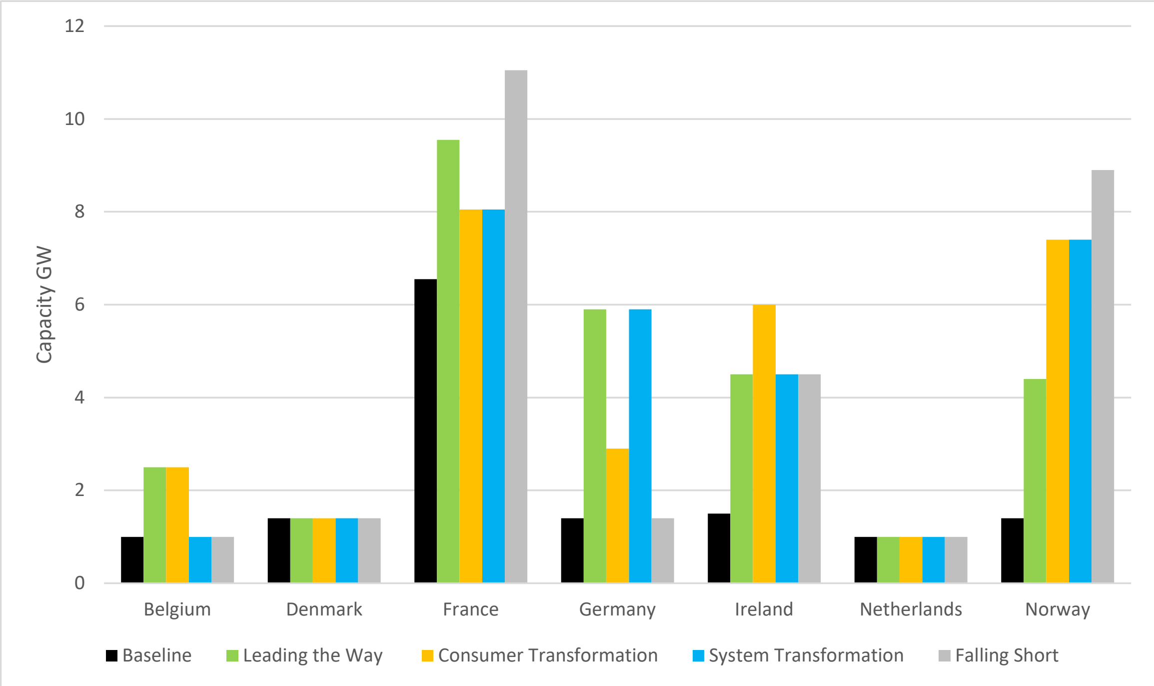

Figure 5: Total interconnection capacity for each FES scenario by connecting country

Figure 5 shows the same data as Figure 4 but shows interconnection capacity by connecting country for each FES. *Leading the Way* and *System Transformation* result in high additional capacity volumes to Germany. *Falling Short* has the highest additional capacity to France and Norway. The electricity market in Ireland[4] results in increased capacity in all four FES scenarios. Denmark and The Netherlands see no increases in capacity in any FES scenarios.

[4] This covers both Northern Ireland and the Republic of Ireland.

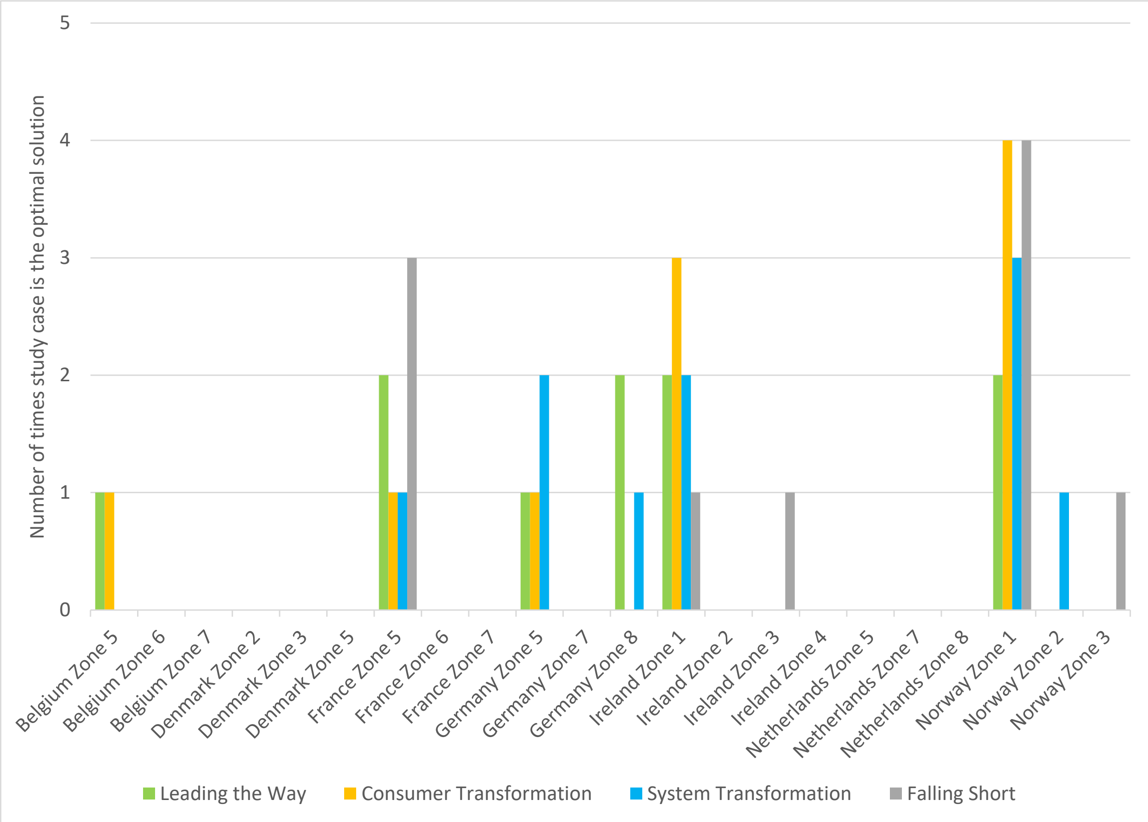

Figure 6: Number of times a study case is the optimal solution

Figure 6 shows the number of times that each study case is optimal across the four scenarios. Just three study cases are optimal in roughly three quarters of iterations, with 13 of the 22 study cases never being optimal. This shows that both the connecting country and the Great Britain connection zone are critical in deciding which study case will provide the highest NPV. However, many of the study cases that are not optimal in any of the iterations also provide significant levels of NPV. The results show there is value for additional interconnection capacity over and above those with Cap and Floor Window 1 and 2 approvals.

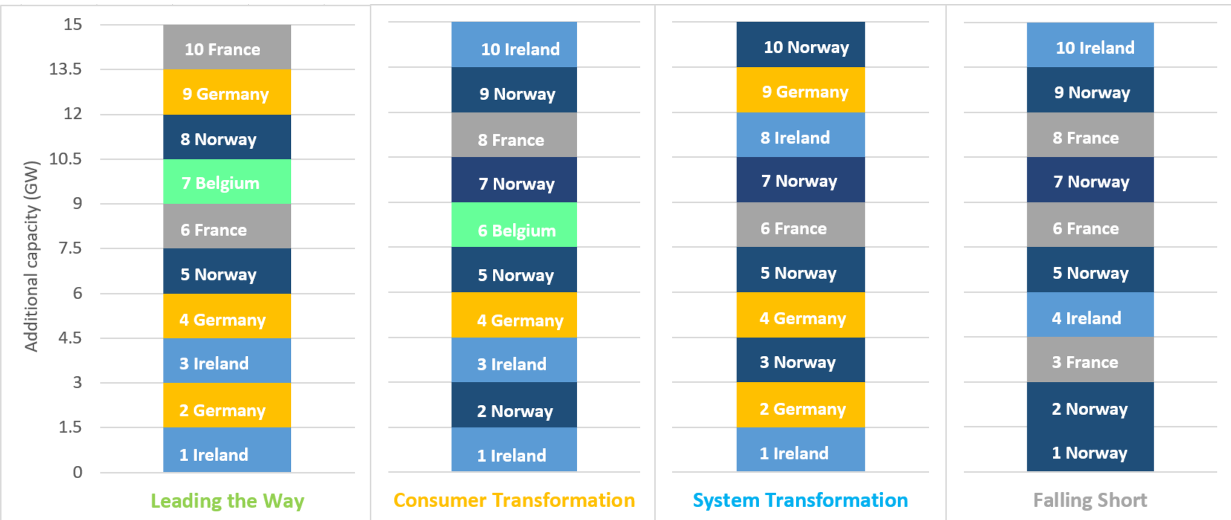

Figure 7: Order of winning study case connecting country for each of the four Future Energy Scenarios

Figure 7 shows the order of the winning interconnector option for the ten iterations for each FES scenario. It shows that the winning options are dominated by connections to Norway, the electricity market in Ireland, France and Germany.

Net Present Value of interconnection

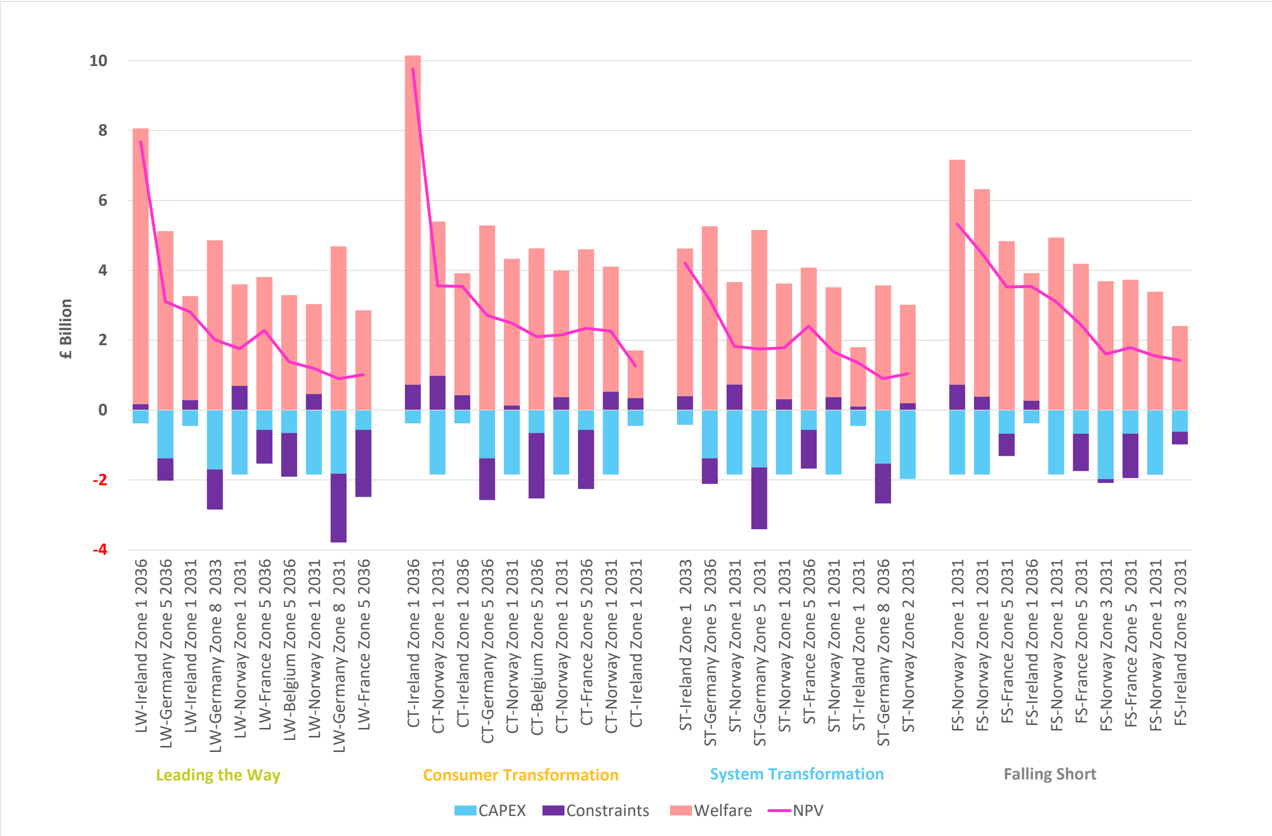

Figure 8: Net Present Value of each optimal study case for the optimal path for each FES scenario

Figure 8 shows the optimal paths across the four scenarios and the variations in NPV relative to the base case for each iteration. It also gives a breakdown for each NPV by welfare, CAPEX and constraint cost. CAPEX is always negative relative to the base case because of the additional costs of the interconnector, such as the cable and the converter stations. As the additional interconnector may result in constraint savings or additional costs relative to the base case, the chart shows constraints as positive for certain study cases and negative for others. As stated previously, the lengths of the paths are the same for each FES scenario, i.e. ten iterations.

For *Leading the Way*, *Consumer Transformation* and *System Transformation*, the winning study case for iteration 1 is Ireland Zone 1. The study case produces high levels of welfare, particularly in *Leading the Way* and *Consumer Transformation*. Levels of NPV fall after most iterations. This is to be expected, as the addition of another interconnector reduces arbitrage opportunities between connected markets as price differentials are reduced.

Figure 8 shows that for nearly all study cases for all four FES scenarios, interconnectors to the electricity market in Ireland and Norway result in constraint savings. It is only in the later iterations in *Falling Short* that interconnectors to Ireland or Norway result in an increase in constraint costs.

The dominant contributing factor to NPV in virtually every optimal study case is welfare. Levels of welfare are broadly similar across all four FES scenarios, except for the first iterations for *Leading* *the Way* and *Consumer Transformation*. Many of the study cases that did not win (which do not feature on the optimal paths) also provide positive NPV, primarily driven by welfare. The methodology for this year's interconnector analysis only considered SEW for Great Britain and the connecting country. Considering SEW for all of Europe may have given different results.

Figure 8 shows that there were still positive levels of NPV by iteration 10 in all four FES scenarios, suggesting that in theory, even more additional interconnection could be added. In theory, the process could have continued until NPV declined to zero, but this would have resulted in unrealistically high levels of interconnection, with no account of the impact on system operability.

Import and export flows

Figure 9 shows the modelled electricity import and export volumes for Great Britain after ten iterations of interconnectors have been added to the default system of each FES scenario. By convention, imports are defined as positive values and exports as negative values. Additionally, the net flow is marked in each case by a horizontal black bar.

In all cases considered in this analysis, there are net exports from Great Britain to other countries or markets. The *Falling Short* scenario shows more balanced levels of imports and exports than the other scenarios, particularly in 2035. The general trend is for net flow to increase in the later years, driven by higher exports.

In many of the cases considered, export volumes are significantly larger than import volumes. This reflects the high levels of Great Britain's renewable capacity, and the potential for interconnectors to transport excess generation to neighbouring markets. Apart from *Falling Short*, imports remain relatively flat across the three years modelled, indicating a consistent requirement for imports for balancing requirements within Great Britain.

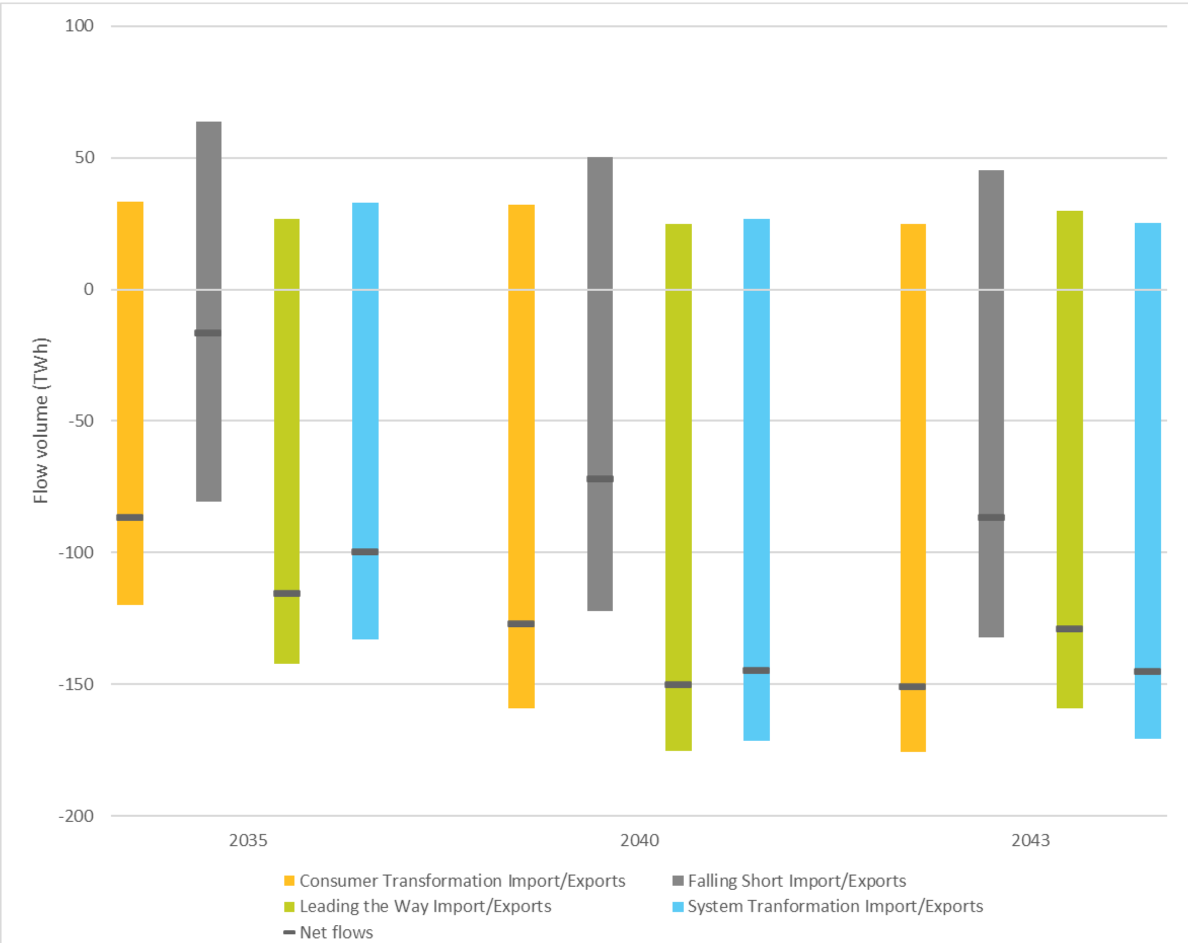

Figure 9: Aggregated import and export volumes for Great Britain after full iteration paths of each scenario

Figure 10 shows the same import and export information as Figure 9, but broken down by connecting country. Imports in all years and FES scenarios are heavily dominated by French and Norwegian interconnectors.

Levels of electricity exports to other countries are somewhat dependent upon the FES scenario being considered. The availability to export to any country will be driven by the optimal path found under each FES scenario, and therefore the interconnector capacities deployed in each case. For example, the final interconnector capacity to Germany is highest in the *Leading the Way* and *System Transformation* scenarios. This is correlated against the modelled export volumes, which are highest for these two scenarios. Similar behaviour can be observed for Belgian exports, due to Belgian interconnectors being chosen only within the *Consumer Transformation* and *Leading the Way* scenarios.

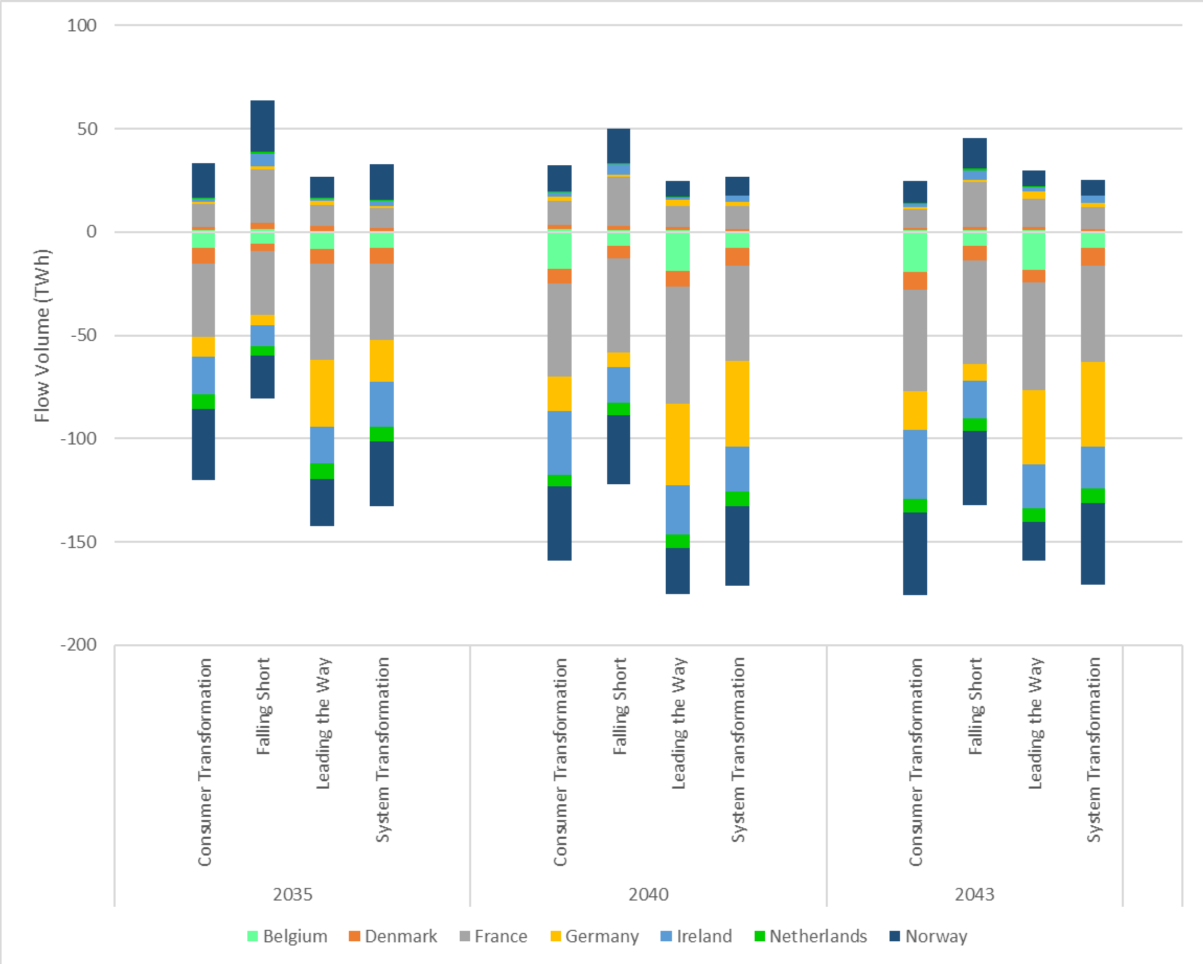

Figure 10: Import and export electricity volumes, broken down by connecting country, for iteration 10 of each Future Energy Scenario

Regional analysis

The following section looks at the impact of the geographic location of each GB connection zone of the interconnector study cases on the results of the modelling. The following group of figures show each of the 22 study cases for each of the ten iterations, with the study cases sorted with the most northerly GB connection zone on the left of the chart and the most southerly GB connection zone on the right of the chart.

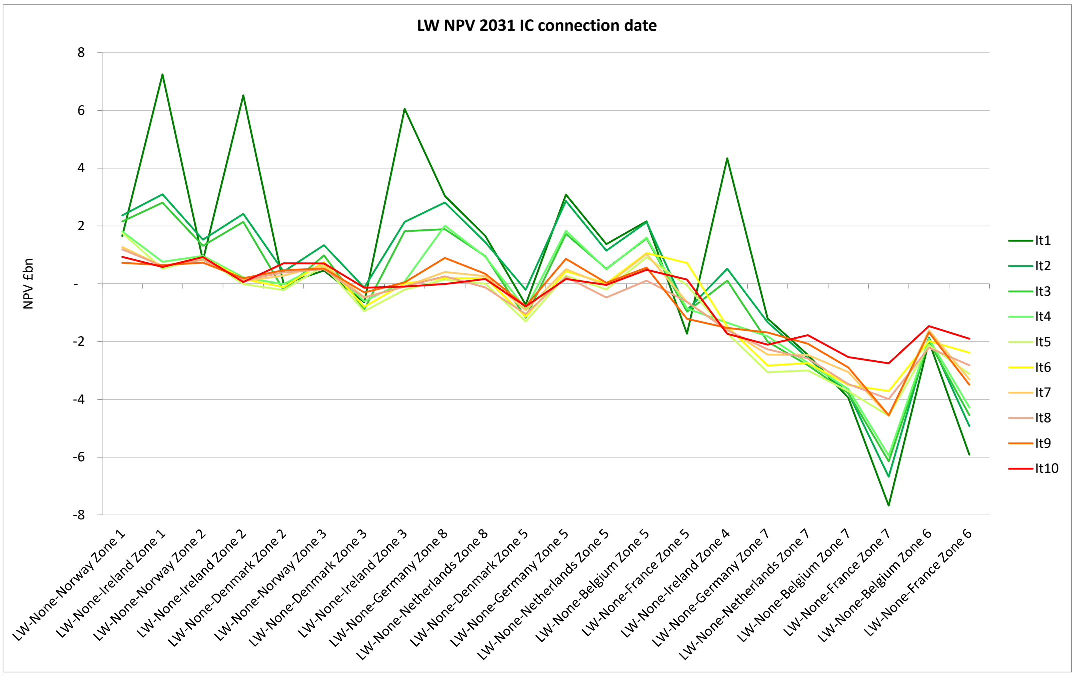

Figure 11: Net Present Value for each study case for each of the ten iterations for Leading the Way, for the 2031 interconnector connection date

Figure 11 shows that, in general, the level of NPV falls across subsequent iterations, as shown previously in Figure 8. The figure above also shows that the level of NPV also tends to fall across a single iteration based on the location of the GB connection zone, i.e. in general, each line is higher on the left of the chart and lower on the right. NPVs are higher for the study case with the most northerly GB connection zone and lowest for the study case with the most southerly GB connection zone.

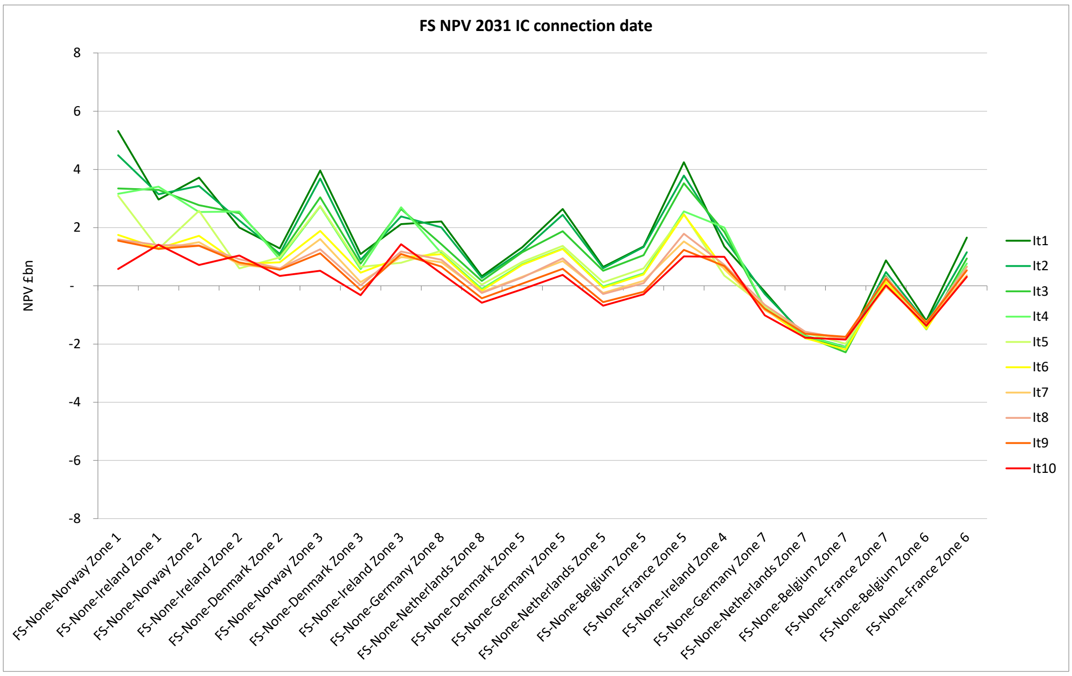

Figure 12: Net Present Value for each study case for each of the ten iterations for Falling Short, for the 2031 interconnector connection date

Figure 12 shows the NPV data for iterations 1 to 10 for the *Falling Short* scenario. It shows the same effect as Figure 11 but not as pronounced. There is a reduction in the NPV across the study cases for a particular iteration when moving from the most northerly GB connection zone to the most southerly connection zone.

Figure 13 and Figure 15 take the same approach but only show the welfare data rather than the NPV.

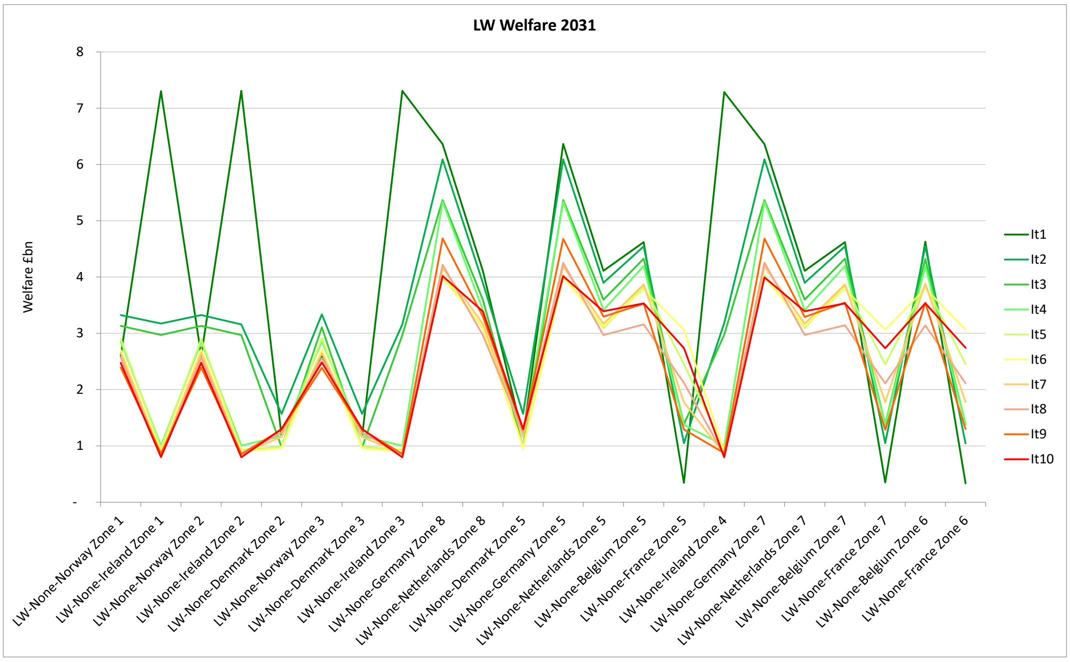

Figure 13: Welfare for each study case for each of the ten iterations for Leading the Way, for the 2031 interconnector connection date

Figure 13 shows that whilst the level of welfare falls across subsequent iterations, there is no clear reduction in welfare across the study cases for a particular iteration. This is to be expected as welfare is driven by the price differentials between Great Britain and the connecting country or market, and not by the geographic location of the GB connection zone. This can be seen more clearly in the following chart.

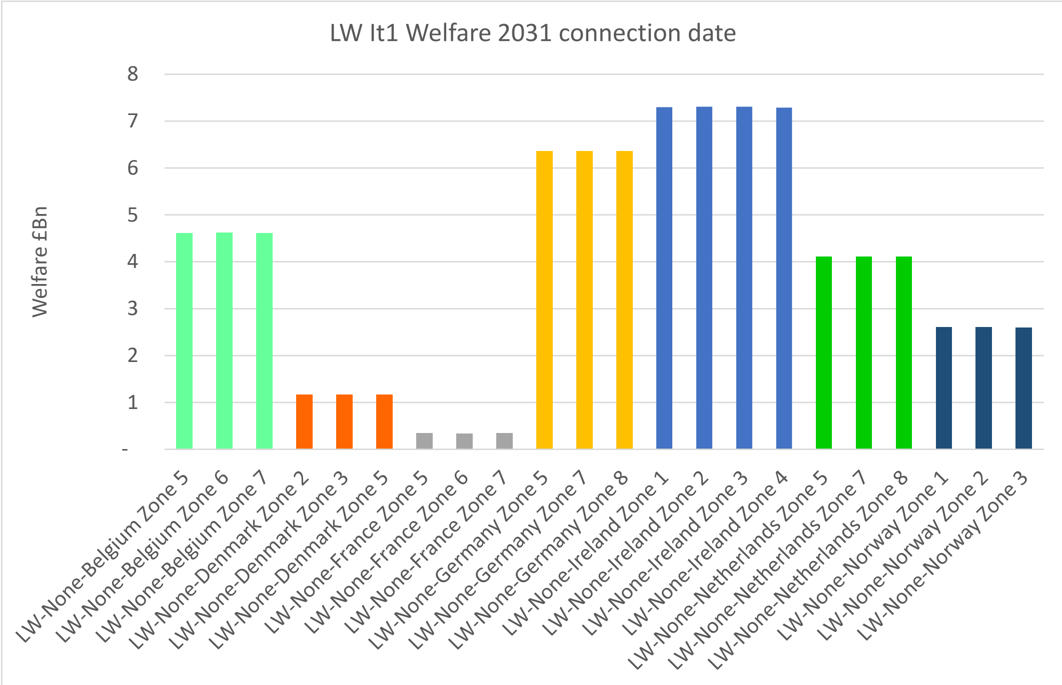

Figure 14: Welfare for all study cases for iteration 1 for Leading the Way

Figure 14 clearly shows that the level of welfare is the same for each study case connected to the same connecting country.

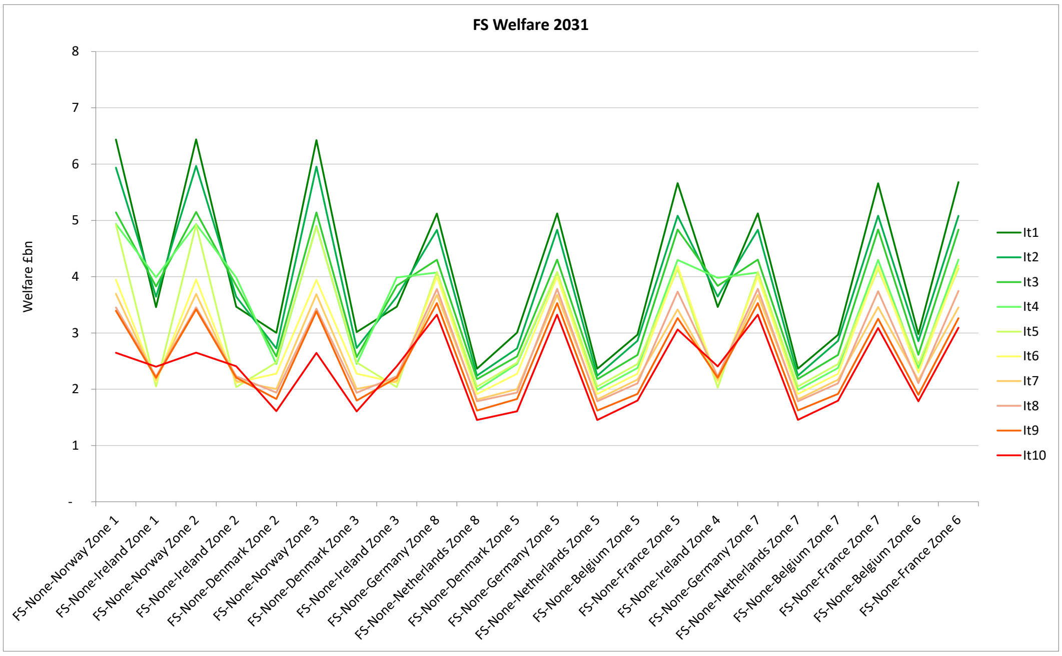

Figure 15: Welfare for each study case for each of the ten iterations for Falling Short, for the 2031 interconnector connection date

Figure 15 shows the welfare for iterations 1 to 10 for the *Falling Short* scenario. It shows that compared to Figure 13 the levels of welfare in the *Falling Short* scenario are different from those in *Leading the Way*, and as shown in Figure 8, the levels can be higher.

The following two charts show the variations in constraint costs across all study cases for all ten iterations for the *Leading the Way* and *Falling Short* scenarios.

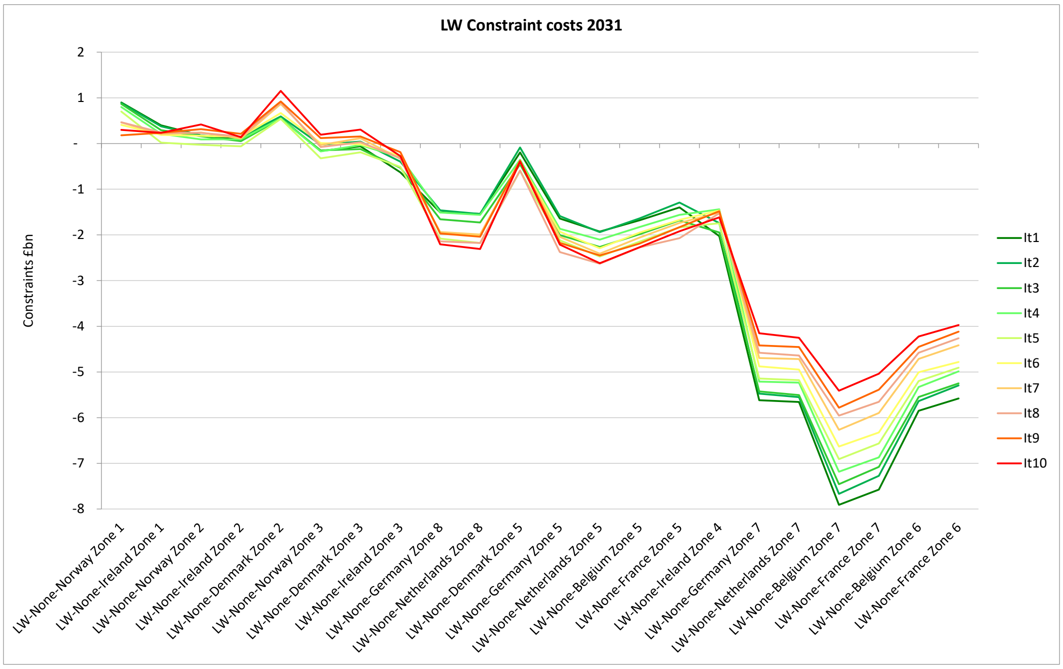

Figure 16: Constraint costs for each study case for each of the ten iterations for Leading the Way, for the 2031 interconnector connection date

Figure 16 shows additional constraint costs as negative numbers. The study cases are sorted with the most northerly GB connection zone on the left of the chart and the most southerly GB connection zone on the right of the chart. The chart shows that, overall, the level of additional constraint costs falls across subsequent iterations. The figure above also shows that the level of additional constraint costs tends to increase across a single iteration based on the location of the GB connection zone. In general, each line is higher on the left of the chart and lower on the right, i.e. constraint costs increase moving from the left to the right. Additional constraint costs are lowest for the study case with the most northerly GB connection zone and in some cases constraint costs are reduced, i.e. the chart shows positive values. Additional constraint costs are highest for the study case with the most southerly GB connection zone.

The high levels of exports seen across all study case interconnectors result in significant increases in constraint costs for those connected in Southern England, as large volumes of electricity from offshore wind are transported from Scotland through England resulting in additional balancing mechanism actions to relieve congestion on the network.

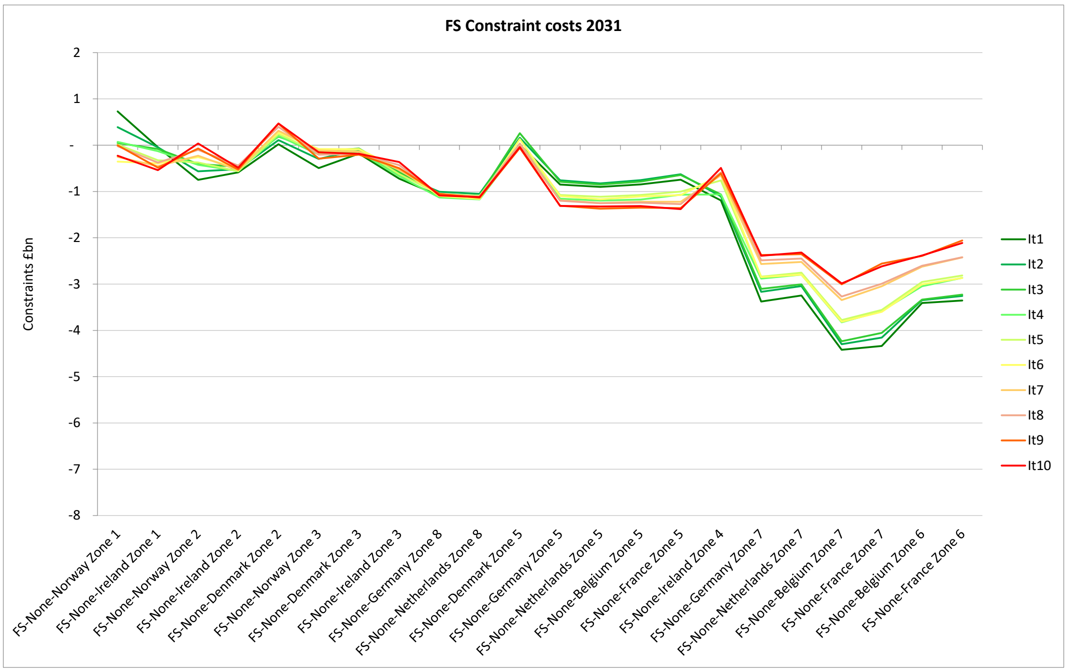

Figure 17: Constraint costs for each study case for each of the ten iterations for Falling Short, for the 2031 interconnector connection date

Figure 17 shows the constraint costs for iterations 1 to 10 for the *Falling Short* scenario. It shows the same effect as Figure 16 but not as pronounced, as *Falling Short* has lower levels of exports. The figure shows that the level of additional constraint costs tends to increase across a single iteration based on the location of the GB connection zone, i.e. in general, each line is higher on the left of the chart and lower on the right. Additional constraint costs are lowest for the study case with the most northerly GB connection zone and highest for the study case with the most southerly GB connection zone.

Care should be taken when interpreting the results. The impact of an interconnector on the absolute levels of constraint costs will be dependent on many factors, including supply and demand assumptions, associated network capabilities, import/export levels and the number and location of other interconnectors in the scenarios. However, there are several high-level themes from this analysis that are to a certain extent independent of those factors:

- The level of increase or decrease in constraint costs is dependent on the geographic location of the GB zone the interconnector connects into and the import/export split on the interconnector, which will be driven by the wholesale price difference between Great Britain and the connecting country or market.
- When the interconnector connects to the South of England and is exporting for significant periods of the time, constraints are increased because the export flows across the interconnector lead to increased network flows across large parts of the network, leading to increased balancing actions and higher constraint costs.
- When the interconnector is connected in Scotland, the high volumes of export flows can lead to reduced constraints by exporting supplies from areas of low demand, high levels of renewable generation and limited network capability, resulting in less flows across the network from North to South and reduced balancing actions.

Offshore Hybrid Assets

The main analysis undertaken used 22 study cases consisting of point-to-point interconnection options for various GB connection zones and connecting countries. This section investigates the impact on NPV of considering Offshore Hybrid Assets (OHAs) and comparing their performance to point-to-point interconnection.

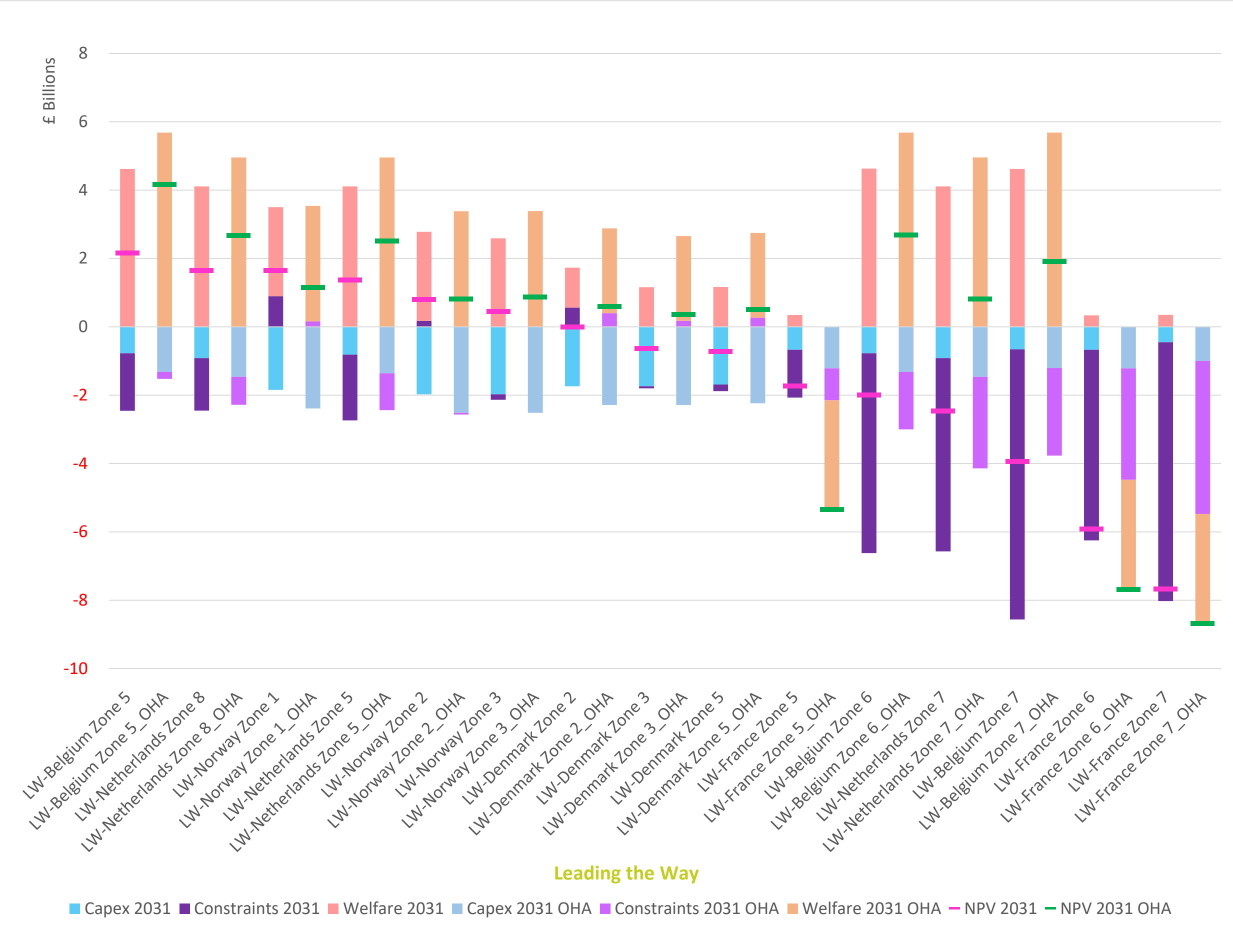

Figure 18: NPV comparison of point to point and offshore hybrid asset study cases for iteration 1 for Leading the Way for 2031 connection date

Figure 18 shows a selection of fifteen point to point study cases for the connecting countries Belgium, Denmark, France, The Netherlands and Norway, ranked with highest NPV on the left and lowest NPV on the right. Next to each point-to-point study case is the equivalent study case combination of GB connection zone and connecting country for an Offshore Hybrid Asset (OHA). The OHA includes the connection of a 1.5 GW offshore windfarm. The figure is for iteration 1 for *Leading the Way*.

The figure shows that in ten of the fifteen study cases NPV is higher in the OHA option than the point-to-point option. In five of the study cases the OHA option has a positive NPV compared to a negative value in the point-to-point equivalent case. The higher NPV in the ten cases is due to several factors. Firstly, the level of welfare generated in the OHA cases is higher than in the equivalent point to point case. Secondly the level of constraint costs in the OHA cases is lower than in the equivalent point to point case. This is to be expected, as the offshore windfarm in the OHA displaces generation that in the point-to-point case that has to flow through Great Britain. The increased flows in the point-to-point case may be from offshore wind farms in the North of England or Scotland, resulting in increased constraint costs. These two factors offset the increased CAPEX costs in the OHA study cases, resulting in higher NPVs.

For the Belgium Zone 5 case, the OHA produces increased levels of welfare compared to the point-to-point, because the reduction in exports from Great Britain across the OHA compared to the point-to-point results in a reduction in producer welfare which is more than offset by an improvement in consumer welfare. Constraint costs for the Belgian Zone 5 OHA are considerably lower than those for the point-to-point equivalent for the reasons stated above. The increases in welfare and reductions in constraint costs more than offset the increases in CAPEX for the OHA, hence the Belgian Zone 5 OHA has a much higher NPV than the point-to-point interconnector.

Care should be taken when interpreting the results. The results shown in Figure 18 are for a single iteration. Whilst the results suggest that in two thirds of the cases NPV is higher in the OHA case compared to the point-to-point, the results from subsequent iterations may be different. In addition, there is considerable uncertainty around the CAPEX values for OHAs. We have used the latest data available in the public domain, but the costs assumed here may be overly optimistic or pessimistic for an OHA in a particular location.

System Operability

Interconnectors can provide system operability benefits but can also result in additional system operation challenges and costs.

Interconnectors are increasingly becoming a key source of flexibility on the electricity system and in the future will constitute a significant portion of the overall supply and demand mix. Accessing flexibility and balancing services on interconnectors will become key for maintaining system operability and as a key element in achieving competition across all market participants. Interconnectors are technically a flexible and capable asset with significant potential for consumer benefit. Interconnectors are already able to participate in balancing services and other commercial services if they choose to do so, but the extent to which this potential can be realised varies significantly across the interconnectors currently connected.

Operational challenges will increase as more interconnectors connect, but these may be mitigated by potential market and regulatory changes. Over the last decade, more interconnectors have connected to the Great Britain system and have contributed to an increase in balancing costs. As more interconnectors connect, resulting in increased flows across the network, we will need the right operational tools to manage flows on the interconnectors, otherwise we will be exposed to increasing balancing costs. Many existing interconnectors have different commercial arrangements in place due to a lack of mandatory code requirements, differences in regulation across borders, and optionality on whether to provide within-day capacity trading platforms. As a result, some interconnectors are more flexible than others which has a direct impact on local balancing and system constraints.

Grid Forming vs Grid Following

Grid forming is the ability of a plant to respond instantaneously to system disturbances such as faults. Synchronous generators have an inbuilt inherent capability to provide a grid forming capability. As such, they contribute to qualities such as inertia and fault infeed. This is very different to the current generation of renewable based/converter-based plant, which are generally classified as grid following plants. A grid following plant is one where the plant will see a fault or disturbance on the system, undertake calculations and then provide a response later. As such, grid following plants are not synchronised with each other and do not contribute to attributes such as inertia and short circuit level, which are fundamental to secure system operation.

The absence of new renewable plant without a grid forming capability will cause significant operational, security and reliability issues. Interconnectors and OHAs that are equipped with voltage source convertors (VSC) have the technical potential to provide grid forming services, such as voltage regulation and frequency response. Grid forming is a fundamental pre-requisite to achieving zero-carbon operation and maintaining secure system operation in the most economic manner.

Frequency Response

All UK appliances and electrical equipment are designed to work at 50 Hz. To maintain a stable system frequency of around 50 Hz, (set by the Security and Quality of Supply Standard), we procure a range of response services. These services automatically react to changes in system frequency (increases or decreases, triggered by changes in generation or demand), which can happen in both normal operational scenarios and in post-fault situations. As we transition to net zero and a greater proportion of renewable generation capacity, we will have to manage more frequent and faster frequency fluctuations, and we will need to procure services from zero-carbon technologies.

In the last decade the average annual system inertia has fallen by around 40 per cent. Lower inertia means that system frequency is less resistant to change, so it will change more quickly when subject to an event, like a sudden loss of generation or demand. The combination of lower inertia and larger losses due to larger loads means that frequency can move quickly.

Stability support to the grid has traditionally been supplied as an inherent by-product of synchronous generators. More asynchronous generation and variable sources of generation create uncertainty in generation and demand forecasts and increased fluctuations in frequency. Scenarios with more asynchronous and variable sources of generation will likely require more Response and Reserve services.

Interconnectors and OHAs that are equipped with voltage source convertors (VSC) have the technical potential to provide frequency response services.

Reactive Power

Reactive power describes the background energy movement in an alternating current (AC) system arising from the production of electric and magnetic fields. Devices that store energy through a magnetic field produced by a flow of current are said to absorb reactive power; those that store energy through electric fields are said to generate reactive power. Reactive power services are how we makes sure voltage levels on the system remain within a given range. We instruct generators or other asset owners to either absorb reactive power (decreasing voltage) or generate reactive power (increasing voltage).

The flows of reactive power on the system will affect voltage levels. Unlike system frequency, which is consistent across the network, voltages experienced at points across the system form a 'voltage profile', which is uniquely related to the prevailing real and reactive power supply and demand. We must manage voltage levels on a local level to meet the varying needs of the system. The energy transition and decarbonisation of the electricity system continues to affect voltage management across the transmission network. More reactive power capability and utilisation is required as the reactive power requirement continues to increase and available capacity decreases.

VSC (Voltage Source Converter) technology is a type of high-power electronic converter that allows the provision of reactive power. This means that interconnectors and OHAs using this technology can be used to assist with voltage control.

Restoration

Restoration (formerly known as Black Start) is the process used to restore power in the unlikely event of a total or partial shutdown of the National Grid Electricity Transmission system. The restoration service can be procured from a range of Power Generating Modules (PGM) or HVDC systems that have the capability to re-start from shutdown without reliance on external supplies.

The current restoration approach is to use contracted large power stations and interconnectors to energise sections of the transmission system using local demand to establish stable power islands in line with pre-agreed Local Joint Restoration Plans (LJRPs). Subsequently, other generators will join the growing system, and the synchronisation of power islands progressively takes place to re-energise the whole network and restore demand across the country until full restoration is completed. For this strategy to work, generation must meet demand in local areas whilst maintaining voltage and frequency requirements: the inherent capability of voltage source capability (VSC) interconnectors make them suitable to providing restoration services.

Interconnectors and system balancing

Interconnectors connecting to the Great Britain National Electricity System (NETS) currently do not participate in the Balancing Mechanism. As interconnectors do not participate in the Balancing Mechanism, we are unable to issue BOAs (Bid Offer Acceptances) on interconnectors post gate closure, hence we are reliant on capacity trading or emergency instructions to control interconnector flows. The range of market tools interconnectors use varies from one interconnector to another. Some have day ahead capacity auctions or are implicitly coupled with day-ahead energy auctions, while others do not participate the day-ahead market at all. Similarly, some have a form of intraday market and others have none. Some offer SO-SO within-gate trading. All interconnectors offer Emergency Assistance/Emergency Instruction allowing real-time emergency control. This variance between interconnectors can lead to increased balancing costs due to different trading and flow control arrangements.

Our ability to reliably trade capacity over interconnectors requires established, liquid and competitive commercial markets to enable it to trade at market reflective prices and to ensure trades are not easily unwound by other market participants. To date, the main market mechanisms to allow this are the day ahead and intra-day markets. Therefore, any interconnector that operates without a within-day or day-ahead market structure means we are unable to alter the flow across the interconnector. This means we will undertake all possible non-discriminatory market-based solutions to ensure the most cost-effective method to secure system operability. Changing interconnector flows post gate-closure can be very expensive - managing interconnector flows by trading in capacity markets is considerably cheaper than resorting to balancing actions.

Securing the largest loss of load

We must ensure the system can operate safely with the loss of the largest load on the system. For larger capacity interconnectors this can present an issue if all the interconnector’s flow feeds through a single circuit breaker. This can result in increased balancing costs in securing additional system response. Additionally, single circuit connections create challenges when scheduling maintenance. It would be beneficial therefore for any future interconnector that could represent the largest system loss to be designed with multiple circuit breakers.

Environmental Analysis

For each addition of interconnector capacity, overall system properties are recalculated. This includes the carbon emissions associated with network operation. These can be compared against a base case, where no new interconnector capacity has been deployed. The carbon emissions being calculated in these instances are not necessarily directly related to the build of the interconnector, but rather how the system responds when each option is connected. For example, an interconnector build might help to mitigate curtailment on the system, increasing RES production and reducing reliance on thermal production in Great Britain.

An example of this analysis is shown in Figure 19, which demonstrates changes in carbon emissions for each of the 22 possible interconnector builds when compared to the originally defined system within the *Consumer Transformation* scenario, i.e. the baseline. Emissions changes are calculated for three individual modelling years, 2035, 2040 and 2043, shown by different colour bars. Increase in emissions are shown as positive values and reductions as negative.

Figure 19 shows that some interconnector options increase carbon emissions relative to the baseline, i.e. relative to the system excluding the new interconnector. This is due to an increase in thermal generation with the inclusion of the additional interconnector. Conversely, some options reduce emissions, as the inclusion of the interconnector results in a reduction in thermal generation levels.

Total carbon emissions decrease across the timeline, i.e. from 2035 to 2043, as renewable proliferation grows; these are not shown on the chart. In other words, the baseline carbon emissions are highest in 2035 and lowest in 2043. This accounts for the variation in emissions changes when comparing across modelled years – since overall emissions are highest in 2035, there is greater potential to change the system. In later years, where decarbonisation is more extensive, there is lower flexibility to make system changes which can significantly change emissions, hence lower values for these years in Figure 19.

Some interconnector build options are more conducive to reducing carbon emissions within the electricity network. In the case of *Consumer Transformation*, interconnector options to Denmark and Norway appear most favourable in terms of environmental impact, particularly in 2035. Again, it should be stressed that these changes in emissions are a measure of how the electricity system is able to respond to the build, rather than any emissions inherent within the build of the interconnector itself.

The environmental impact of interconnector builds can also vary by iteration. For *Consumer Transformation*, the geographical trends remain the same across each of the ten iterations performed, although the values of emissions changes do alter. For example, there is a reduction in the maximum available emissions saving from iteration 1 to iteration 10, suggesting that additional interconnector capacities will have diminishing returns with regards to driving environmental changes.

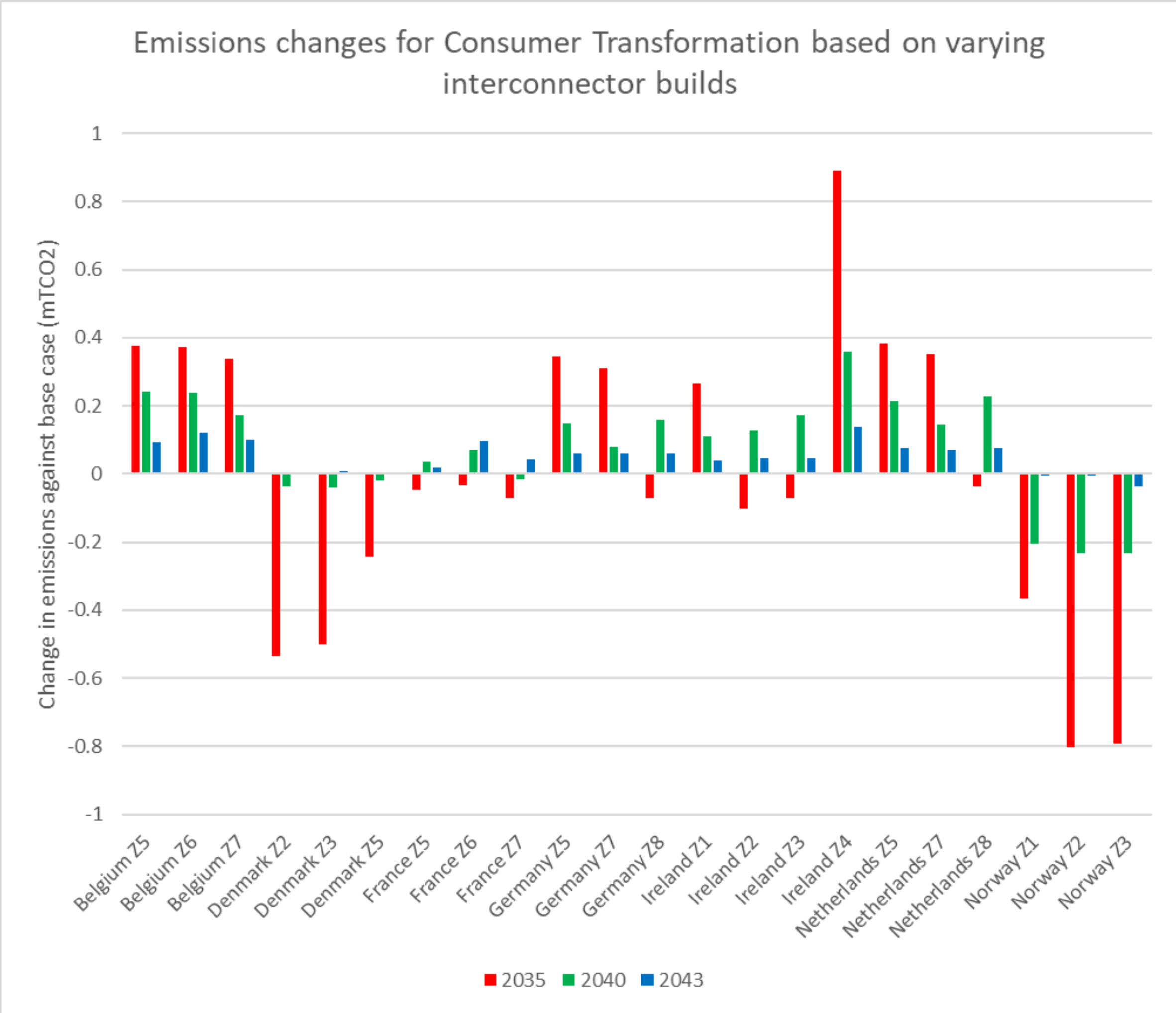

Figure 19: Emissions changes for Consumer Transformation build options in iteration 1

Figure 20 to Figure 22 show the corresponding carbon emissions data for the other three FES scenarios which were analysed. There are some key differences to *Consumer Transformation*:

- ***Falling Short***: French interconnectors demonstrate a more significant reduction in emissions in 2035 (comparable to Danish interconnectors). Across many of the build options, 2035 emissions changes are lower than those in *Consumer Transformation*.
- ***Leading the Way***: Danish interconnectors no longer create significant short-term reductions in emissions, leaving only Norwegian interconnectors as those which reliably reduce emissions across the set of years considered.
- ***System Transformation***: Interconnectors to the electricity market in Ireland reduce carbon emissions in 2035. Emissions in 2040 and 2043 are more negligible across many of the interconnector options, whereas in other scenarios there is still usually some noticeable impact.

It should also be noted that these charts only represent iteration 1 from each set of analysis. Some points to note from later iterations include:

- ***Falling Short***: The ability of Norwegian interconnectors to create carbon emissions reductions decreases rapidly through the iterations. Additionally, French and Danish interconnectors produce less favourable results in later iterations, to the point that they generally increase emissions (although still at a lower rate than interconnector options which already increased emissions).

- ***Leading the Way***: The ability of Norwegian interconnectors to create carbon emissions reductions again decreases through the iterations. The ability of most interconnector options to produce any emissions reductions remains sporadic, and highly dependent upon the year and geography considered.
- ***System Transformation***: In a similar way to *Falling Short*, Norwegian interconnectors have lower ability to reduce system emissions by later iterations, and the Irish and Danish interconnectors are mostly neutral.

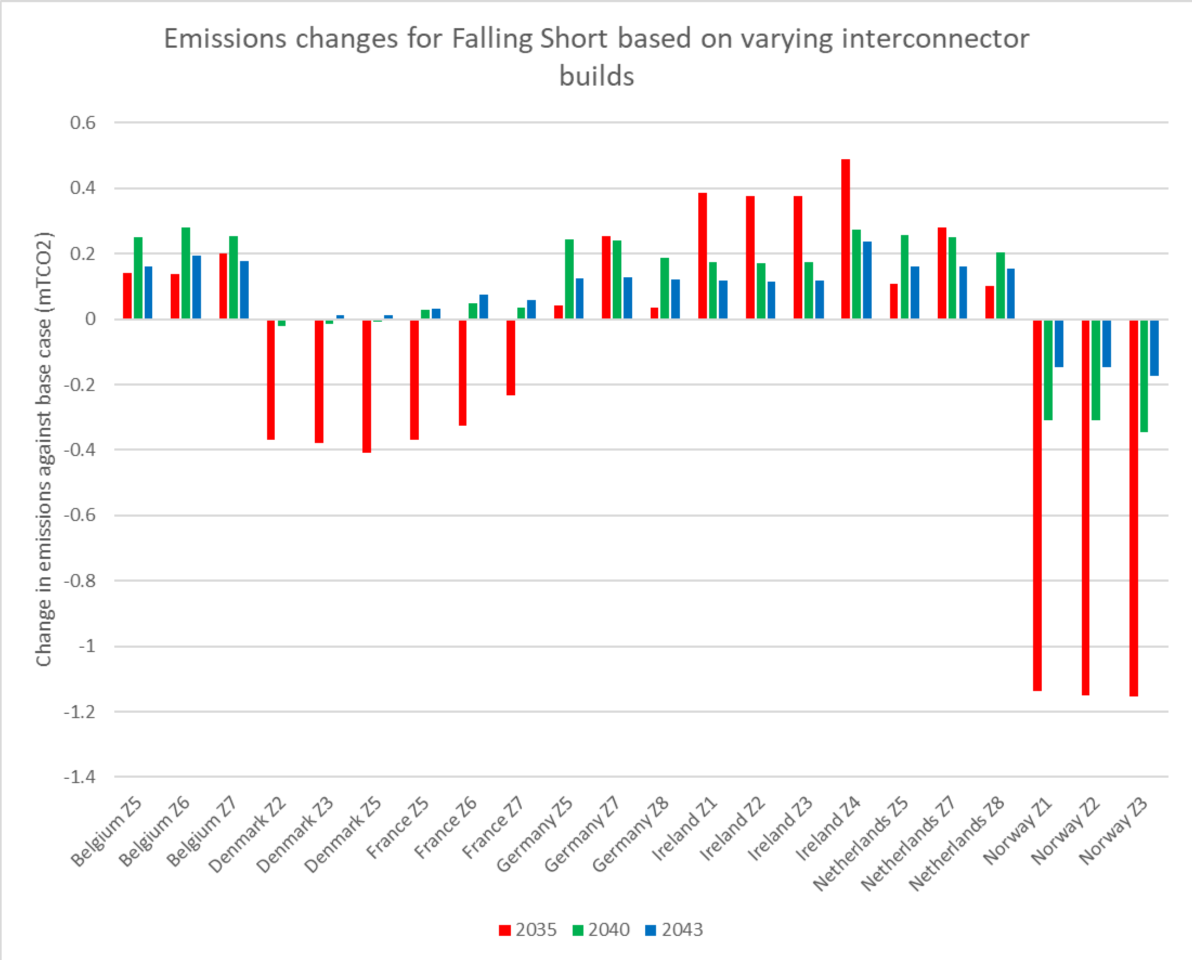

Figure 20: Emissions changes for Falling Short build options in iteration 1

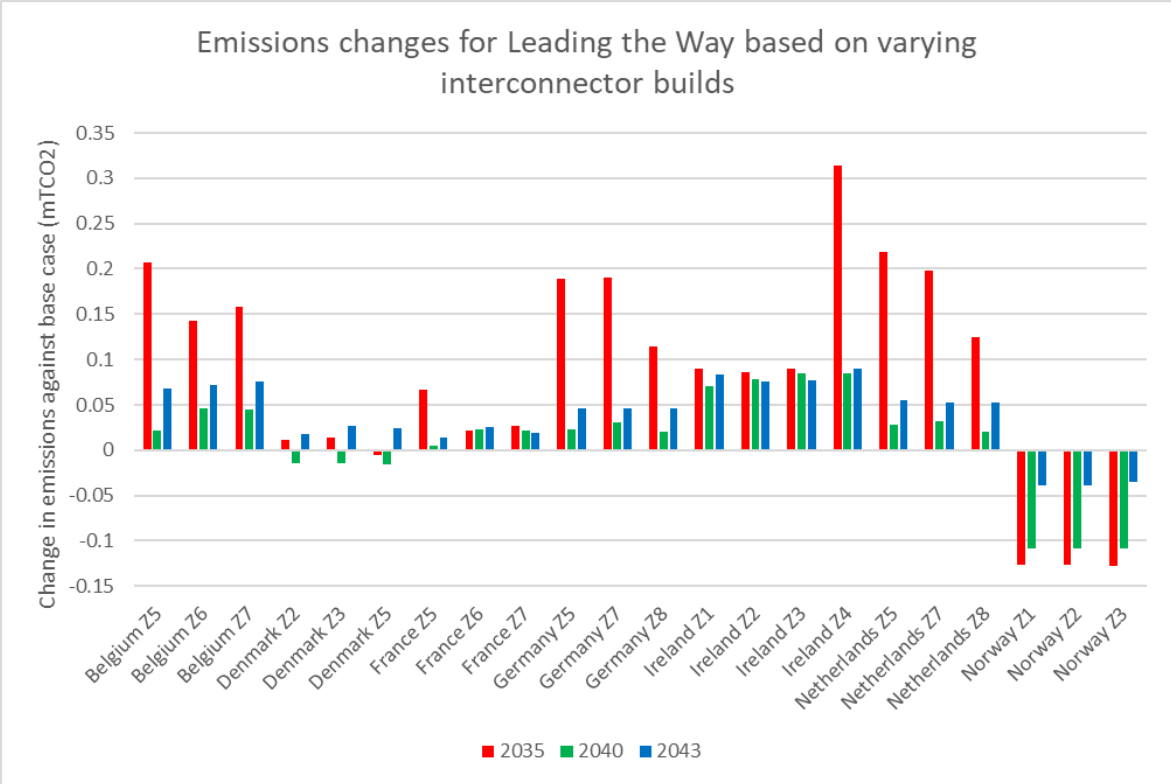

Figure 21: Emissions changes for Leading the Way build options in iteration 1

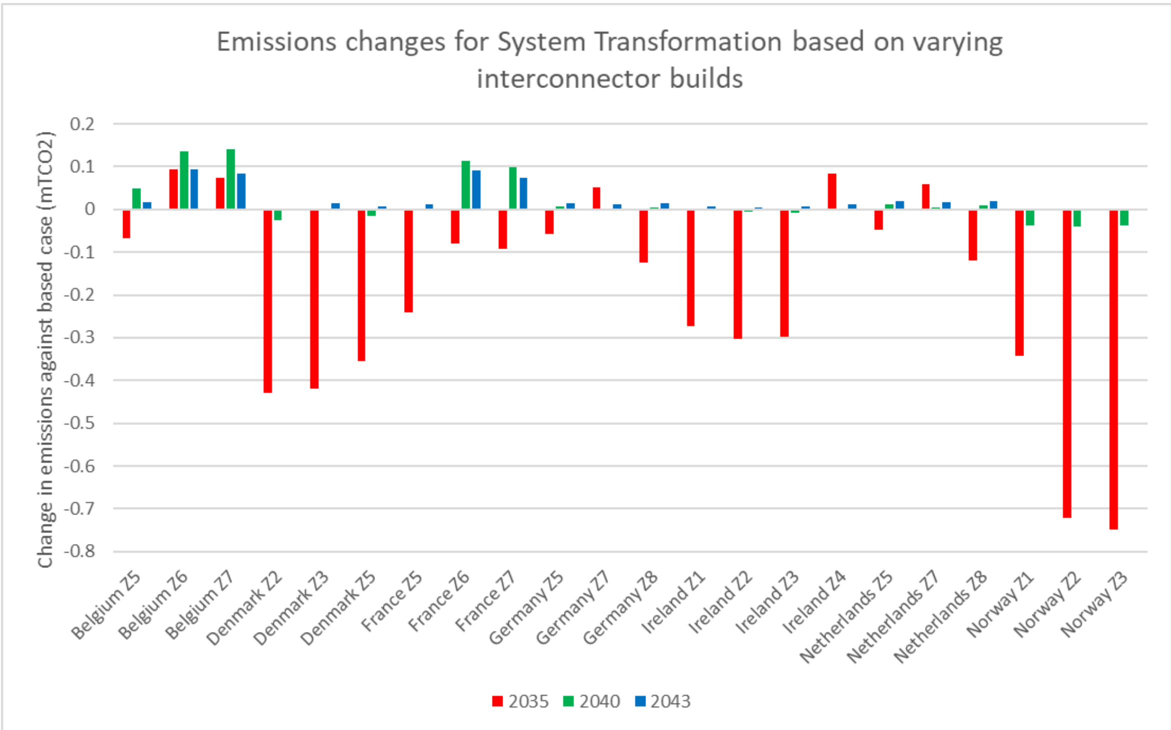

Figure 22: Emissions changes for System Transformation build options in iteration 1

The following four charts show the progression of carbon emissions associated with the modelled system across the optimal path of each FES scenario. This shows the impact of each iteration on the results. We have focused on 2040 emissions data for this set of analysis. Since some interconnectors can be chosen for a 2036 build, the 2035 results would be unaffected by those iterations.

The pathways within these charts outline the interconnector builds in the order they were chosen across the optimal path. In each case, the change in emissions is denoted by a vertical bar, coloured green for a decrease in emissions or red for an increase in emissions.

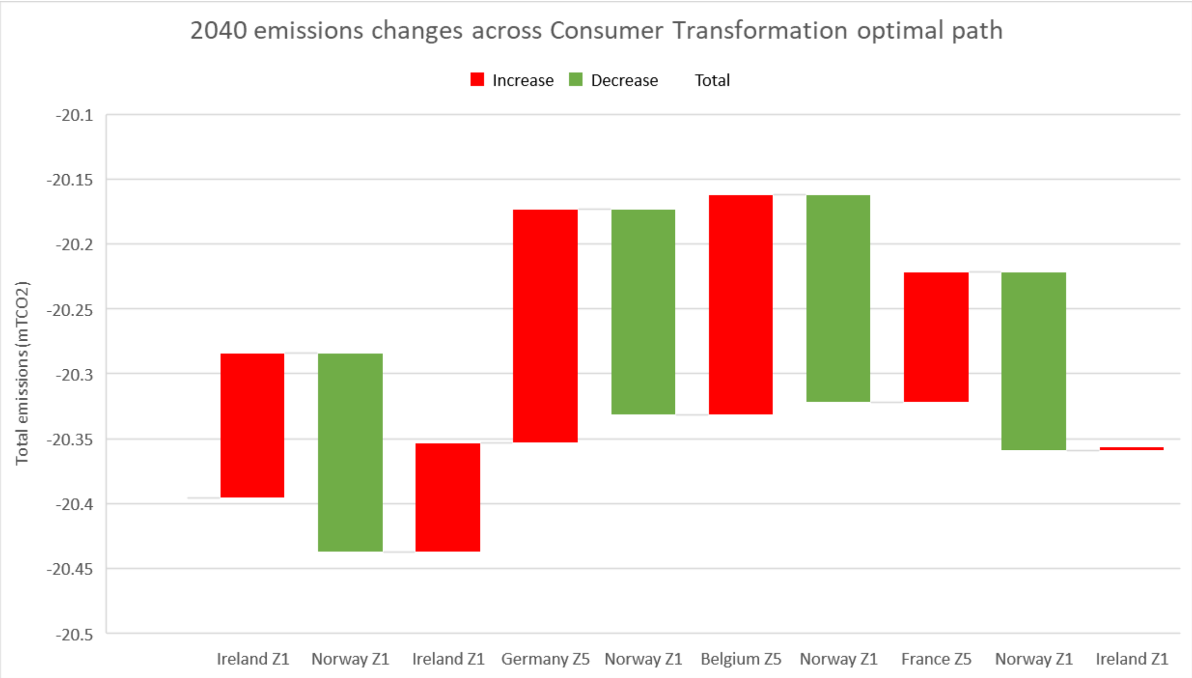

Figure 23: Emissions changes across the Consumer Transformation optimal path in 2040

Figure 23 shows the changes in emissions along the optimal path for *Consumer Transformation*. Across the full optimal path, there is an increase of 0.04 $mTCO_2$ in system emissions. Each of the four interconnector builds to Norway is associated with an emissions reduction, whereas each other iteration increases emissions within the system.

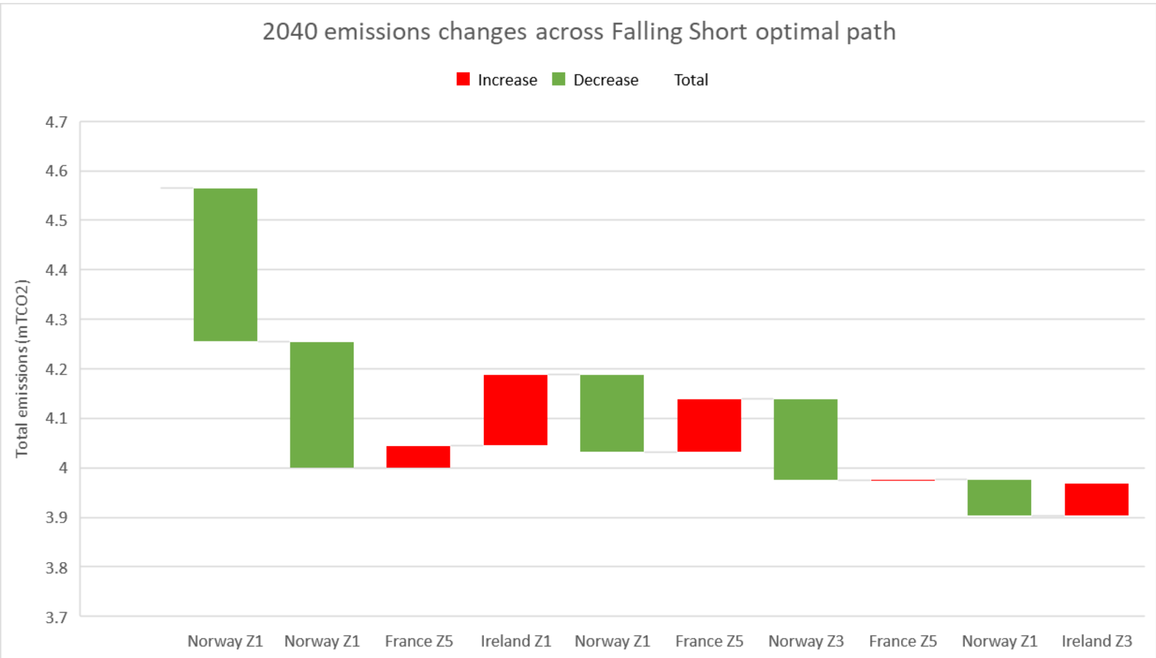

Figure 24: Emissions changes across the Falling Short optimal path in 2040

Figure 24 shows the changes in emissions along the optimal path for *Falling Short*. Across the full optimal path, there is a decrease of 0.6 $mTCO_2$ in system emissions (albeit from a higher starting point than the other scenarios). As observed across the *Consumer Transformation* optimal path, interconnector builds to Norway significantly reduce carbon emissions, while other iterations increase emissions.

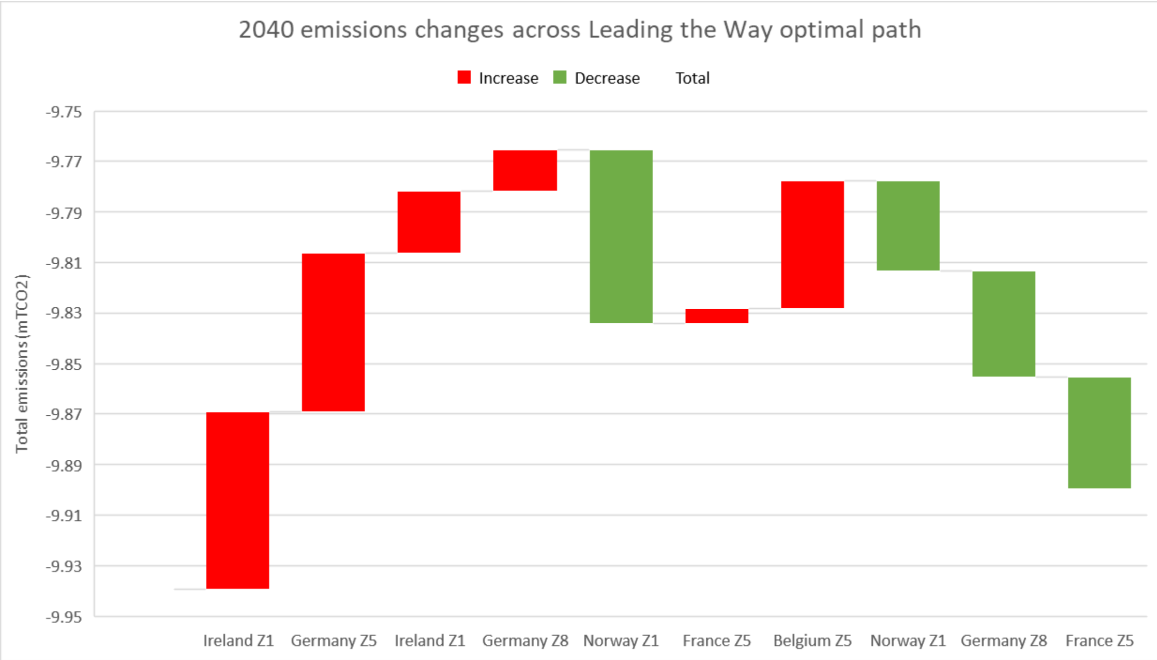

Figure 25: Emissions changes across the Leading the Way optimal path in 2040

Figure 25 shows the changes in emissions along the optimal path for *Leading the Way*. Across the full optimal path, there is an increase of 0.04 $mTCO_2$. Additional interconnection to Germany results in an increase in emissions in the iterations 2 and 4, and a reduction in iteration 9, and most of the emissions decreases occur during the later iterations.

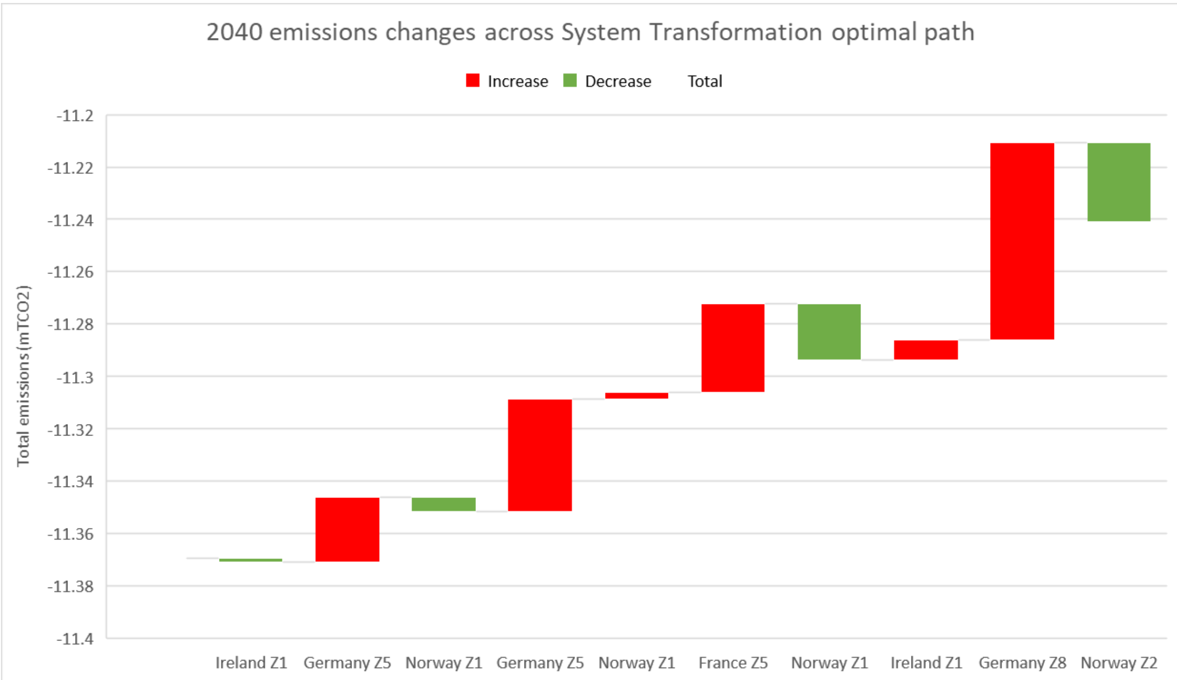

Figure 26: Emissions changes across the System Transformation optimal path in 2040

Figure 26 shows the changes in emissions along the optimal path in *System Transformation*. Across the full optimal path, there is an increase of 0.13 mT CO_2, the largest increase across any of the FES optimal paths. In particular, the iterations where interconnectors are built to Germany contribute towards the largest emissions increases.

In summary, when considering the optimal path of interconnector additions of each FES scenario, 3 out of 4 demonstrate an overall increase in carbon emissions for the 2040 modelled year. The one scenario for which this is not the case represents the least decarbonised electricity grid, *Falling Short*. This trend is also replicated within the optimal path emissions for 2043.

The emissions changes in 2035 along the optimal path are more complicated; as previously mentioned, some interconnector builds chosen do not take effect until 2035, so these iterations have no change in carbon emissions. Of the four FES scenarios, there are three for which carbon emissions are reduced in 2035. In these cases, the interconnectors which would reduce emissions are typically built earlier, which therefore results in a pattern of iterations where carbon emissions either reduce or remain static. This creates an aggregated reduction across the full path.

The exception in 2035 is *Leading the Way*. For this scenario, only Norwegian interconnectors consistently reduce emissions in 2035, and only two iterations choose these options on the full path. Additionally, many options which are built earlier than 2035 contribute to significant increases in emissions.

Through this analysis, it has become clear that the geographical factors heavily influence the response of system emissions to the addition of interconnectors. A clear example of this is seen in the first two iterations of the *Consumer Transformation* optimal path, where interconnectors added to the electricity market in Ireland and Norway create opposite responses. A deeper dive into this behaviour is presented later.

Renewable Energy Supplies integration

As Great Britain continues to decarbonise its electricity network, large capacities of renewable generating technologies will be added to the network. However, the network was built to a specification of a small number of thermal power plants, which are not necessarily located in the same geographical areas. This means that, in some cases, the network's present design may not be suited to support integration of renewables, resulting in potential curtailment where electricity production exceeds the ability of the network to transport power to relevant demand centres.

Theoretically, the addition of interconnectors can benefit the system by reducing the curtailment of Renewable Energy Supplies (RES). This can be achieved by providing additional options for transfer of power, which are not limited by these existing network constraints. Additionally, the flexibility to import and export from different markets allows Great Britain to manage discrepancies in its supply and demand more effectively.

Figure 27 shows the modelled reduction in curtailment volume for each iteration along the optimal path of every FES scenario, for the year 2040. Different generation types are broken down by colour in the stacked bars. For every interconnector added along the optimal path, these reduced curtailment volumes would therefore aggregate, creating an increasingly efficient use of the available RES capacity on the system.

Every iteration produces a reduction in curtailment volume. Indeed, every non-optimal option (not shown) also produced the same effect, albeit to varying degrees.

The greatest overall reduction in curtailment volume, after a full optimal path, is for *Consumer Transformation*, with 52.9 TWh of avoided curtailment. *Consumer Transformation* has high levels of RES deployment, but lower capacities of electrolysis plant than *Leading the Way*. Since electrolysis can provide an opportunity to mitigate network constraints through use of strategic, flexible demand, this combination in *Leading the Way* leads to lower levels of RES curtailment. Through the addition of interconnectors, these high levels of curtailment in *Consumer Transformation* are therefore reduced.

Leading the Way (46.7 TWh) and *System Transformation* (44.5 TWh) have similar volumes of avoided curtailment through their optimal paths, while the interconnectors added in *Falling Short* create the lowest amount of curtailment reduction (30.1 TWh). However, *Falling Short* also has a much lower initial volumes of curtailment, and this is not indicative of a lower ability of interconnectors to reduce curtailment volume in this scenario.

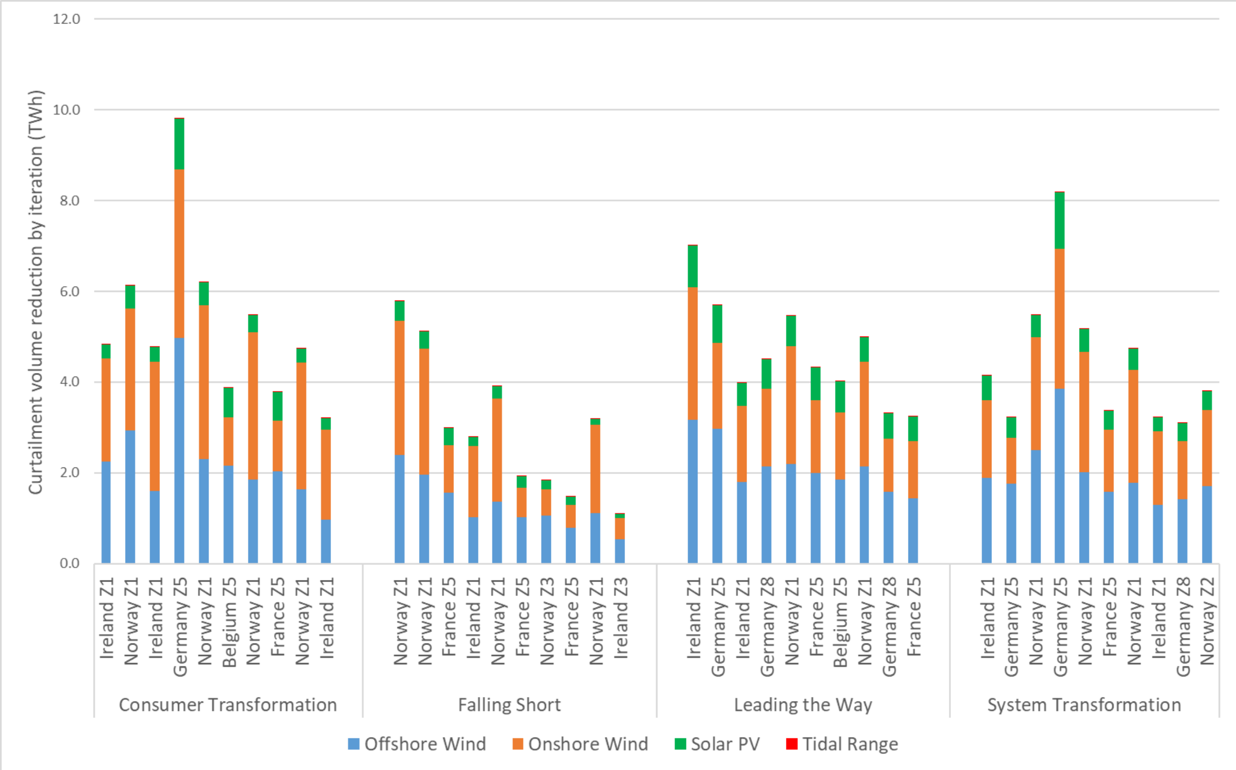

Figure 27: Avoided curtailment volumes across the optimal paths of each FES scenario, broken down by generation type, for 2040

Iteration deep dive

As has already been noted, the addition of an interconnector nearly always results in a reduction in RES curtailment, as interconnectors provide access to an alternative network to the constrained onshore system. However, previous analysis has already demonstrated that carbon emissions can increase or decrease when an interconnector is added, suggesting that the resultant change in the generation mix is more complex than a simple increase of RES production.

To illustrate these interactions, this section takes a deeper dive on two iterations in the optimal path of *Consumer Transformation*. As noted from the earlier results, the chosen iterations produce opposing changes in carbon emissions.

The winning build for iteration 1 is Ireland Zone 1, which is chosen for build in 2036. The winning build for iteration 2 is Norway Zone 1, which is chosen for build in 2031. Based on previous analysis, interconnectors in the electricity market in Ireland in this scenario typically increase emissions and Norwegian interconnectors mostly decrease emissions across all scenarios. Therefore, the geography of both the onshore network and the connecting country must be a driving factor behind the emissions change across the first two iterations.

Generation mixture by network zone

The modelled Great Britain electricity system results in net exports across all the FES scenarios. With the addition of each interconnector, both the exports and imports across the system grow in response, determined by the market conditions which will allow for the best recovery on investment. Since each interconnector added results in an overall increase of net flow from Great Britain to other countries, this necessitates an increased output from the domestic generation fleet to meet this additional demand.

From these two iterations of *Consumer Transformation*, the required additional demand is roughly similar, but is met through two different responses. We primarily consider the response of RES technologies and thermal generation, both of which change during these iterations.

Figure 28 shows a map of the zones used within our modelling.

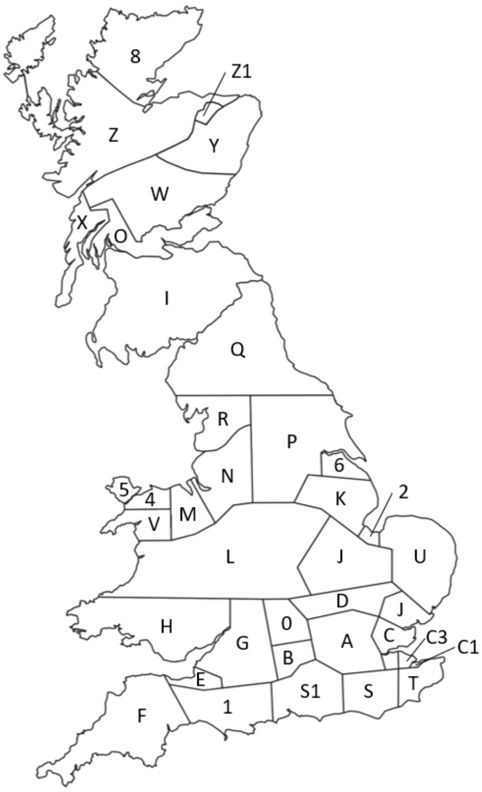

Figure 28: Map of GB zones used in modelling.

Figure 29 shows a heatmap of changes to renewable production after iteration 1 in the optimal path for *Consumer Transformation*, for the year 2040. Onshore zones coloured in red shows areas where renewable production decreases relative to the base case, whereas the darkest green areas show network zones where additional interconnector capacity has initiated the largest increase in RES production within that zone.

Iteration 1 selected the electricity market in Ireland Zone 1 as the winning scheme. This connects to network zone I, which is the southernmost zone in Scotland. This addition of interconnector capacity heavily promotes the output of renewables in zone I, which is the region with the largest increase in RES production. There are also reasonable RES production increases for some of the northern network zones in England, and minor RES production increases for most network zones within Great Britain.

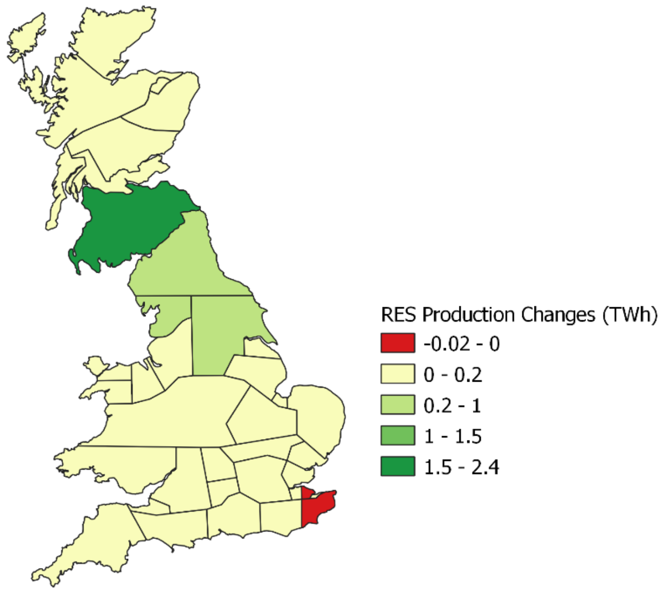

Figure 29: Heatmap of changes in RES production by onshore network zone for CT Iteration 1, in 2040

Figure 30 shows the corresponding information for iteration 2 of this optimal path. This time, the winning interconnector scheme is Norway Zone 1, which connects to network zone Y. This area roughly approximates to Aberdeenshire in Scotland. In contrast to the previous iteration, RES production is heavily increased in some northern network zones in Scotland. While RES production increases are highest in Zone I, the increase is less significant than for iteration 1. Additionally, impact on zones in northern England are also significantly reduced compared to iteration 1.

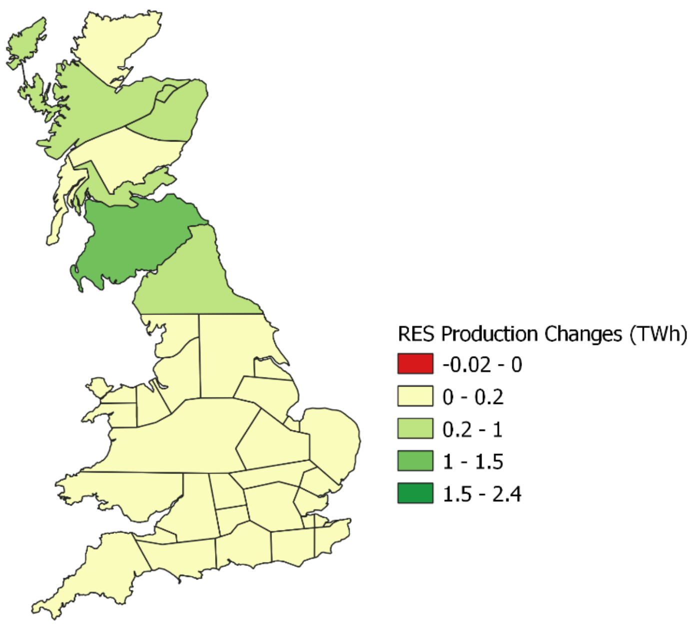

Figure 30: Heatmap of changes in RES production by onshore network zone for CT Iteration 2, in 2040

The ability to access constrained renewables and transport additional power away from the constrained onshore network, depends heavily upon the geography of the network. Curtailment is not significantly decreased in Northern Scotland during the first iteration, because there are internal constraints which could prevent transfer of power in a southerly direction. However, connecting directly into this region allows for additional power to be moved across the interconnector to Norway.

Avoided curtailment by network zone

Figure 30 provides some context about the assumed levels of curtailment within *Consumer Transformation* in 2040. The most significant zones for overall curtailment volume are zone I (Southern Scotland) and zone 8 (Northern Scotland). There is also a significant cluster of curtailment throughout network zones in Scotland and Northern England, and additionally some in East Anglia (zone U) and the South West (zone F).

Even though the winning interconnector in iteration 2 does not explicitly target zone I, curtailment volume reduction is still largest within this network zone, since there is a large overall curtailment volume when compared to other zones.

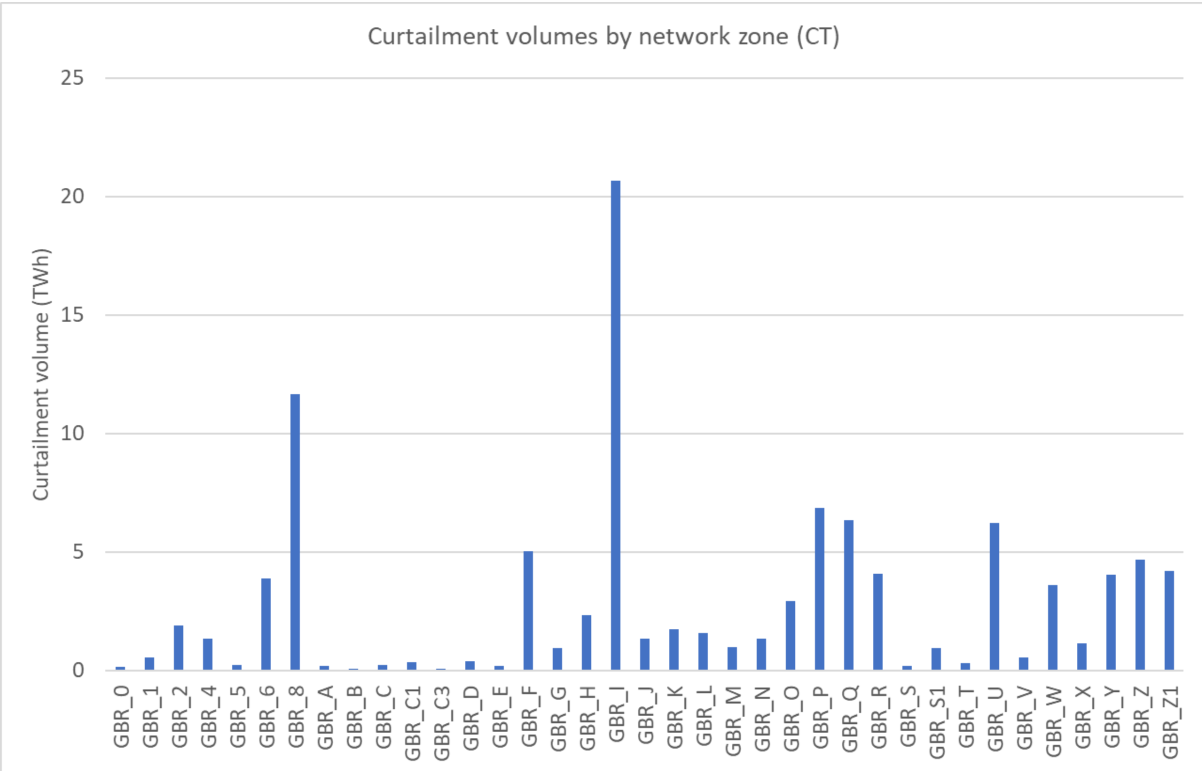

Figure 31: Base curtailment volume for Consumer Transformation in 2040 by network zone.

Figure 31 provides some context about the reduction of curtailment volume, taken as a percentage of the starting point in each network zone. This reduces the skewing effect introduced by zones with large initial curtailment volumes and provides a relative measure of how effectively each interconnector can target specific network constraints.

Although individual zone curtailment reduction volumes in iteration 2 are never as large as the peak achieved in iteration 1, the percentage reductions of curtailment volume in North Scotland zones are very significant in iteration 2, particularly for zone Y where the winning interconnector connects.

Zone 8 has the second largest curtailment volume in 2040 according to the *Consumer Transformation* scenario. Therefore, it would be a desirable outcome to reduce this level of curtailment and use the installed RES capacity more efficiently. However, neither of these interconnectors can provide significant mitigation against this curtailment volume. This would indicate that internal network boundaries still represent significant constraints, which would prevent renewable power created in this network zone exporting across interconnectors. In this case, only an interconnector option which connects directly to zone 8 might have the potential to create notable curtailment volume reductions.

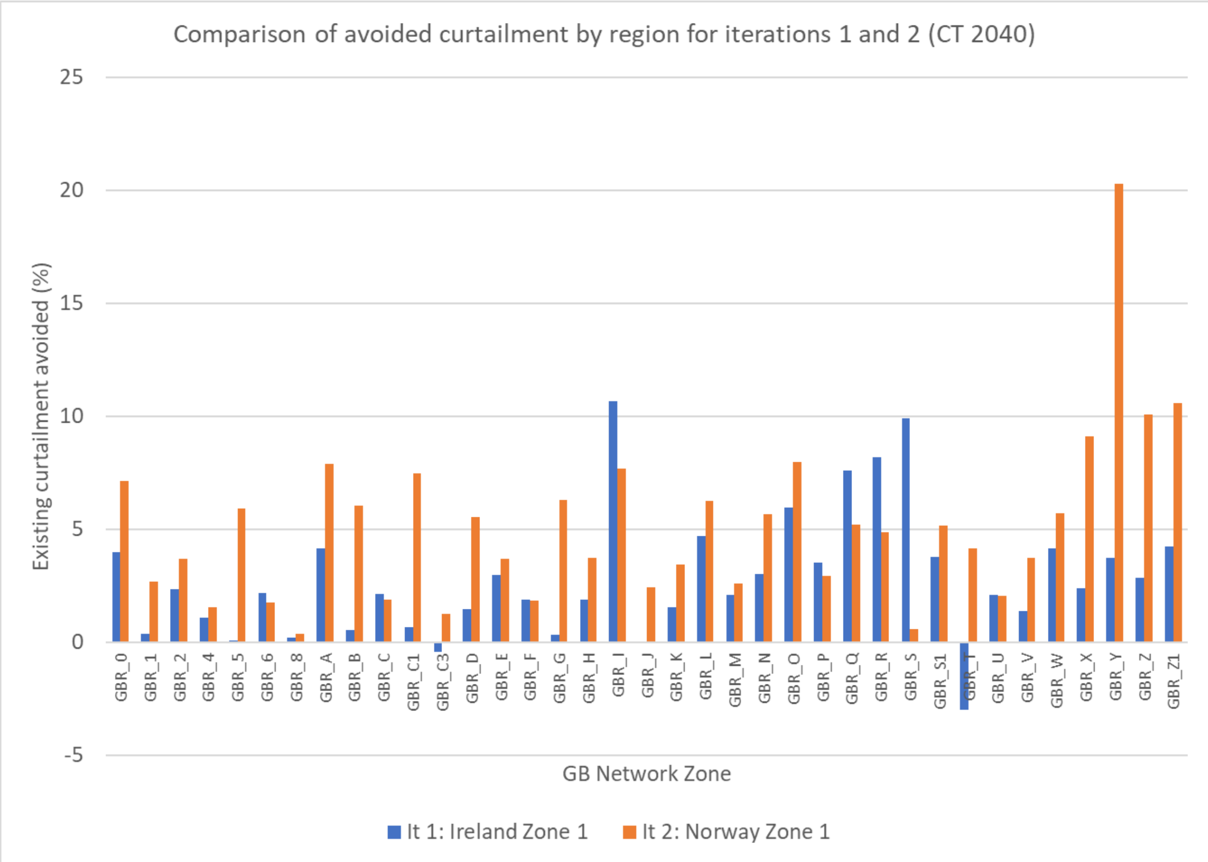

Figure 32: Avoided curtailment in Consumer Transformation in 2040, taken as a percentage of the previous base.

Emissions changes of iteration 1 and 2

The changes in the generation mixture across the two iterations are summarised in Table 2, using larger regions than the network zones. Overall, the two iterations produce similar net power increases when considering the combination of renewables and thermal generation, but this is achieved through two different generation mixtures.

	Iteration 1	**Iteration 2**
RES generation change – South Scotland (TWh)	2.38	1.64
RES generation change – North Scotland (TWh)	0.66	2.01
RES generation change – North England (TWh)	1.05	0.68
RES generation change – Remaining regions (TWh)	0.73	1.81
RES generation change – Total (TWh)	**4.82**	**6.14**
Thermal generation change (TWh)	**0.40**	**-1.04**

Table 2: Changes in generation mix for Iteration 1 and 2 for Consumer Transformation

The build of an interconnector to Ireland in iteration 1 can promote significant increases in RES production in South Scotland, and lower increases across the rest of the country. Therefore, the additional 4.82 TWh of RES production created is supplemented by 0.4 TWh of thermal generation, which contributes towards an emissions increase. In contrast, the build of an interconnector to Norway in iteration 2 produces a lower RES response in South Scotland and North England, but this is compensated by additional RES production in North Scotland and more generally across Great Britain. Combined, this means that thermal generation can be reduced and still allow for net flow conditions to be optimal. This contributes towards the emissions reductions associated with additional interconnector capacity to Norway.

The analysis shows that the impact an interconnector may have on emissions is complex: the ability of an interconnector to reduce constrained renewables, and transport additional power away from the onshore network is dependent upon network capability.