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NESO System Impact Assessment Report

Cap and Floor Window 3 and OHA Pilot Scheme Needs Case Assessment: post-consultation analysis

NESO
National Energy
System Operator

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1. Executive Summary

Ofgem has developed the cap and floor regime to encourage investment in electricity interconnectors. Ofgem's third cap and floor application window ran from 1st September 2022 to 10th January 2023. Alongside this Ofgem ran an Offshore Hybrid Asset (OHA) application period from 1st September 2022 to 31st October 2022. In total nine projects are being assessed as part of the Needs Case Assessment for the Initial Project Assessment for the third window and the OHA pilot scheme.

Ofgem and ARUP developed a new needs case assessment framework for Cap and Floor Window 3 and the OHA pilot scheme. The assessment features a broad set of impact categories, including socio-economic welfare, system operability, constraint costs (balancing market impacts), decarbonisation, security of supply and hard to monetise impacts.

This analysis that the NESO has undertaken is broken down into five main assessment areas. These are:

- **Constraint costs** – quantifying the potential impact of the Window 3 and OHA pilot projects on constraints on the network. Also referred to as balancing market impacts.
- **Frequency Response** – the potential impact of the projects on system frequency.
- **Reactive Power** – the potential impact on system voltage.
- **Restoration** – the potential impact of the projects on restoring power to the system in the unlikely event of a power outage. Restoration was previously referred to as Black Start.
- **Curtailment** – the potential impact of the Window 3 and OHA pilot projects on renewable energy curtailment.

Ofgem published their minded-to position in March 2024, with a consultation closing on 31 May 2024. Based on stakeholder feedback, we have rerun the analysis with several updates:

- For the Nautilus OHA, the capacity of the line connecting the offshore platform to Belgium (Line 2) has been reduced from 3.5GW to 1.4GW
- Demand and generation data for Ireland has been updated to reflect that within the final version of the TYNDP 2022.
- We have included a Constraint Reduction Factor (CRF) to provide an updated forecast of additional constraint costs due to the construction of a new interconnector. The CRF assumes additional reinforcements are developed over and above those already identified and these would reduce future additional constraint costs.
- We have rerun the RES curtailment avoided analysis.
- The frequency response, reactive power support and restoration analyses have not been rerun as the changes to the scenarios would not have resulted in material changes to the results. Hence this report contains the original analysis published in March 2024.

This report provides an explanation of the assessment methodologies that the NESO has used as well as the analysis and results. The report highlights where results have changed compared to the original analysis from March 2024, and provides an explanation as to why the results have changed. The analysis and results of this report, along with the work ARUP has undertaken as part of Ofgem's initial project assessments for the third window and OHA pilot will enable Ofgem to assess the potential impact to GB consumers of the various interconnectors and Offshore Hybrid Assets.

For the First Additional case, when the Constraint Reduction Factor is not applied, additional constraint costs are higher in the latest modelling compared to the modelling undertaken in March 2024, for all projects in all scenarios except for LirIC and MaresConnect. LirIC and MaresConnect show a reduction in additional constraint costs for Leading the Way. MaresConnect also shows a reduction in additional constraint costs in Consumer Transformation.

For the First Additional case, when the Constraint Reduction Factor is applied, additional constraint costs are materially lower than when the CRF is not applied and in nearly all instances the additional constraint costs are lower than in the original (March 2024) results.

For the Marginal Additional case, when the Constraint Reduction Factor is not applied, the additional constraint costs are higher in the latest modelling compared to the modelling undertaken in March 2024 for all projects for all scenarios, except for Nautilus, which shows a reduction in additional constraint costs for all scenarios.

For the Marginal Additional case, when the Constraint Reduction Factor is applied, additional constraint costs are materially lower than when the CRF is not applied and in most instances the additional constraint costs are lower than in the original (March 2024) results.

2. Introduction

Window 3 and Offshore Hybrid Asset Pilot Projects

In August 2020, Ofgem launched a review of their regulatory policy and approach to new electricity interconnectors. Ofgem's interconnector policy review decision[1], published in December 2021, included an intention to launch a third cap and floor application window for electricity interconnectors, alongside a pilot window for offshore hybrid assets (OHAs, previously referred to as multi-purpose interconnectors). Ofgem opened the third application window for electricity interconnectors on 1st September 2022 and closed it on 10th January 2023. Seven projects are being assessed as part of the Window 3 Initial Project Assessment (IPA). The OHA pilot application period ran from the 1st September 2022 to the 31st October 2022, with two projects being assessed.

Table 1: Cap and Floor Window 3 projects and Offshore Hybrid Asset pilot scheme projects[4]

Project Name	Asset Type	Capacity (MW)	Connecting country	GB Connection	Assumed Operation date
Aminth	W3	1400	Denmark	Mablethorpe	01/01/2031
AQUIND	W3	2000	France	Lovedean	01/01/2027
Cronos	W3	1400	Belgium	Kemsley	01/10/2029
LirIC	W3	700	Northern Ireland	Hunterston[2]	01/01/2030
MaresConnect	W3	750	Ireland	Bodelwyddan	01/01/2030
NU-Link	W3	1200	Netherlands	Mablethorpe	01/01/2031
Tarchon	W3	1400	Germany	East Anglia Connection Node[3]	01/01/2030
Lionlink	OHA	1800	Netherlands	Friston	01/01/2030
Nautilus	OHA	1400	Belgium	Grain	01/01/2030

ARUP were employed by Ofgem to update the needs case assessment framework for the Window 3 and OHA pilot: they were then employed separately to undertake the CBA. The assessment includes an expanded set of impact categories, including:

- Socio-economic welfare
- Network costs
- System operability
- Constraint costs
- Decarbonisation
- Security of supply

[1] Interconnector Policy Review - Decision | Ofgem

[2] LirIC initially held a connection agreement for Kilmarnock South.

[3] 'East Anglia Connection Node' refers to a substation yet to be constructed, identified as an optimal location point in GB by the connections process conducted by the NESO for the Tarchon project.

[4] Although Aminth is physically an OHA, it applied via Window 3, and hence for the purposes of this assessment it is classified as a W3 project.

- Hard to monetise impacts.

The analysis that the NESO has undertaken is broken down into the five main assessment areas. These are:

- Constraint costs
- Frequency
- Reactive power
- Restoration
- Curtailment

Frequency, reactive power and restoration (formerly known as Black Start) are all elements of system operability.

This report provides an explanation of the assessment methodologies that the NESO has used as well as the analysis and results. This report, along with the analysis that ARUP has undertaken as part of Ofgem's Cap and Floor Window 3 and OHA pilot scheme assessment will enable Ofgem to assess the potential impact to GB consumers of the various interconnectors and offshore hybrid assets participating in the assessment.

The methodologies used for the NESO's analysis build on the work undertaken in previous Cap and Floor assessments and have been updated to reflect any developments, for example in markets or technologies.

Structure of report

This report is broken down into various sections.

Section 3 provides an overview of the methodology used and the modelling framework.

Sections 4 – 8 cover the five assessment areas covered within the report. These are:

- **Section 4 -** Constraint costs (new modelling and analysis)
- **Section 5 -** Frequency (not changed from March 2024)
- **Section 6 -** Reactive power (not changed from March 2024)
- **Section 7 -** Restoration (not changed from March 2024)
- **Section 8 –** Curtailment (new modelling and analysis)

Each of these sections provides a description and background on the indicator, the methodology used for the modelling and a summary of the results.

Sections 4 - 8 provide the results for each individual assessment area by W3 project and OHA pilot project.

Section 9 provides the results for each individual project by assessment areas. Hence it is possible to see the relative scale of the impact of the assessment areas for a particular project.

3. Overview of methodology

Introduction

The NESO has provided analysis in three main areas:

- **Constraint costs.** This indicator quantifies the constraint impact of the Window 3 and OHA pilot projects for Great Britain. These are also referred to as balancing market impacts. **This has been updated for this report.**
- **System Operability.** This assesses the potential savings that an interconnector or OHA may provide to the grid through the provision of ancillary services, for example reductions in costs of procuring frequency response or reactive power services. The services considered are:
    - **Frequency response** – the potential impact of the projects on system frequency.
    - **Reactive power** – the potential impact of the projects on system voltage.
    - **Restoration** – the potential impact of the projects on restoring power to the system in the unlikely event of a power outage. Previously referred to as Black Start.

      These three elements have not been updated: they are the original analysis from the March 2024 report.
    - **Avoided Renewable Energy Supply (RES) curtailment.** This is an assessment of the level of RES spillage or curtailment that would be avoided due to the addition of an interconnector or OHA. **This has been updated for this report.**

A detailed description of each of the modelling methods used to obtain results for the above areas is included later in this report. The following section outlines the high-level modelling framework used for the analysis.

Modelling framework

As in previous Cap and Floor Windows, to quantify the widest range of potential impacts a particular interconnector or OHA may have, two project build cases were considered:

- **First Additional (FA).** The project is the only one of the C&F W3 or OHA pilot projects that is operational. Each project is analysed individually, alongside the base of window 1 and 2 projects.
- **Marginal Additional (MA)**. The project is the last, or marginal project to become operational. Each W3 project is analysed assuming all the other W3 interconnectors and OHAs are operational, as well as the window 1 and 2 projects.

It is assumed that by considering both the FA and MA cases they represent a credible outer envelope for the potential benefits or disbenefits that a project may provide. Within the FA – MA envelope there is a very large number of combinations of multiple interconnectors and OHAs that would result in outcomes that fall within the FA – MA range of results, but to consider all the possible permutations would be impractical from a modelling perspective.

To assess the possible range of impacts that each W3 or OHA pilot project might deliver, three market scenarios were selected. Each scenario represents a different set of market conditions more favourable or detrimental to additional cross-border capacity. The selection of FES used was based on the amount of cross-border interconnection capacity assumed in each scenario.

The three FES22 scenarios[5] selected for the analysis are:

- **Leading the Way (LW):** it includes high levels of cross-border capacity between GB and connected countries and large volumes of renewable generation. **Leading the Way** represents the fastest credible

[5] Further details on the scenarios used for this analysis are available in the Arup Data Workbook available at: https://www.ofgem.gov.uk/consultation/initial-project-assessment-third-cap-and-floor-window-electricity-interconnectors

pathway to decarbonisation. It requires significant lifestyle changes and consumers use a mixture of hydrogen and electrification for heating.

- **Consumer Transformation (CT):** it includes relatively lower levels of cross-border capacity and lower volumes of renewable generation. **Consumer Transformation** sees the rise of electrified heating, with consumers willing to change their behaviour. The scenario incorporates high energy efficiency and demand side flexibility.
- **Falling Short (FS):** it includes relatively low levels of cross-border capacity and low volumes of renewable generation. **Falling Short** represents the slowest credible pathway to decarbonisation, with minimal behaviour change. There is decarbonisation in power and transport but not in heat.

The fourth FES22 scenario System Transformation (ST) was not used because Consumer Transformation provided capacity levels closer to the middle point between Leading the Way and Falling Short.

The modelling assumes a 25-year life for each of the interconnector and OHA pilot projects: the operational life of the projects may well be longer. The start date was taken from each project submission and when no specific day or month was given, we have assumed the beginning of the relevant year. We have modelled each individual year: this is particularly important when considering constraint costs as there can be significant variations from year to year as supply, demand and network capability assumptions evolve over time. We are not able to model years beyond our normal twenty-year modelling horizon: for later years we take an average of the last three years.

NESO used the weather year 2013 for its modelling and analysis for Ofgem's Cap and Floor Window 3 project. NESO was unable to use an average of the three years 1990, 2007 and 2010, as NESO found that the 1990 weather year produced results that were not credible. This may have been because the temporal resolution of the older weather year data was less granular than the later weather years, which may have caused errors in the output. Hence NESO reverted to using 2013, which is the weather year that NESO has used as an average weather year for most of its constraint cost modelling since 2017.

Weather years can have a significant impact on total constraint costs levels: constraint costs in a high wind year could be significantly higher than those in a low wind year. Although the constraint costs resulting from using weather year 2013 may potentially be slightly lower than the constraint costs resulting from taking the average of 1990, 2007 and 2010, 2013 still represents an acceptable average. Also, it is important to remember that the analysis focuses on additional constraint costs, i.e. the difference between the factual and the counterfactual.

Changes to the modelling assumptions for this report

Based on stakeholder feedback, we have updated various modelling input assumptions:

- For the Nautilus OHA, as the project specifications have evolved, the capacity of the line connecting the offshore platform to Belgium (Line 2) has been reduced from 3.5GW to 1.4GW.
- Demand and generation assumptions for Ireland within FES2022 were based on draft TYNDP2022 data. Stakeholders expressed concern that this did not reflect current projections and hence the demand and generation data has been updated to reflect final TYNDP2022 data. Further explanation can be found in Ofgem's decision document.
- The frequency response, reactive power support and restoration analyses have not been rerun: this report contains the original analysis. Changes in frequency response savings will be minimal, in the range of approximately +/-£10m NPV. Changes in reactive power savings will not be material as the changes in flows across the interconnectors will not have a major impact on the reactive power benefit for each project. There will be no changes in restoration savings due to the changes in modelling assumptions. Restoration services are region-specific and the restoration analysis is not flow dependent.
- We have also included additional analysis regarding constraint costs. We have presented additional constraint costs with and without a Constraint Reduction Factor applied. The original constraint cost analysis published in March 2024 highlighted that for certain projects the additional constraint costs due

to the inclusion of the project could be significant. Stakeholders responded that the additional constraint costs shown in the original March 2024 report were overstated because in practice NESO would recommend additional reinforcements that would reduce future additional constraint costs. Hence a Constraint Reduction Factor (CRF) has been applied to reflect the potential reduction in additional constraint costs if additional network reinforcements are included over and above those already identified though our long-term network planning process. This is explained in detail in the Constraint Costs chapter and a full justification of the Constraint Reduction Factor as a response to stakeholder feedback can be seen in Ofgem's Window 3 decision document. We have shown the additional constraint costs without and with the CRF so that the impact on additional constraint costs solely due to the CRF can be identified.

Key terminology

To aid clarity we have tried to use consistent terminology wherever possible. Some specific examples are:

Additional constraint costs – these are the additional constraint costs that are solely due to the inclusion of a particular W3 interconnector or OHA project.

Total constraint costs – these are total GB constraint costs. They may be for the First Additional case, when only one additional W3 project is included or for the Marginal Additional case, when all nine W3 projects will be included.

Original analysis – this is the analysis included within the original IPA modelling published in March 2024.

Updated analysis – this is the new analysis undertaken for this report, based on stakeholder feedback.

Constraint Reduction Factor – this is the potential reduction in additional constraint costs if additional network reinforcements are included over and above those already identified though our long-term network planning process. Note that this is not to be confused with discounting, which is in this report refers to the process of calculating the present value of a series of future costs.

Modelling strengths and limitations

The key aim of the assessments is to provide Ofgem with a credible and robust range of the potential impacts to GB consumers of the various interconnector and OHA projects.

The NESO has used its pan-European market model BID3 to undertake the constraint costs forecasting. The model has been used to support its long-term network planning work such as the Network Options Assessment (NOA) and the Transitional Centralised Strategic Network Planning (TCSNP).

Long-term forecasting of potential developments in ancillary services is challenging, due to the high uncertainty regarding long term developments in system operation, especially when considering the minimum 25-year lifespan of an interconnector or OHA. When assumptions have been made regarding how these services may develop, we have stated them.

The NESO has worked closely with ARUP to ensure wherever possible the underlying modelling assumptions used by both parties are aligned. Where we have not been able to align exactly, such as with the use of weather years we have provided an explanation as to why the change was necessary and why the chosen solution was appropriate.

The strengths and limitations of each individual assessment area are expanded on for each indicator.

4. Constraint costs

Introduction

This indicator quantifies the potential impact of the Window 3 and OHA pilot projects on constraints on the network. Constraint costs are also referred to as balancing market impacts.

The electricity network has a finite level of capacity. This means that at periods of high demand and supply there are limitations on how much electricity can flow from one part of the network to another. When the level of electricity is greater than the capability of the network, the NESO must take action to protect the network. These events are known as system constraints. The constraints occur when the system is unable to transmit power due to congestion at one or more parts of the network. At times, to ensure system security, the NESO must either reduce generation or increase demand behind a constraint, and either increase generation or decrease demand in front of the constraint to ensure generation and demand remain in balance. The NESO will need to pay generators not to produce electricity in areas behind constraints and pay other generators to increase in areas free of constraints. Constraint costs are the cost of the actions the NESO takes in the balancing market to ensure generation meets demand and the transmission network can operate safely.

There are several types of constraints but one of the most common on the network are thermal constraints. Thermal constraints refer to an area of the network where the power is congested due to the thermal capability of the equipment. If the system is unable to flow electricity in the way required, the NESO will take actions in the Balancing Market to increase and decrease the amount of electricity at different locations on the network.

There are two situations that can cause a transmission constraint:

- **Import:** The energy demand cannot be met by localised generation and the flow on the circuits into that area is limited by the capacity of the circuits.
- **Export:** The generation in the area is not offset by the localised demand and the flow on the circuits out of the area is limited by the capacity of the circuits.

Methodology

Pan-European market modelling

The NESO undertakes constraint cost forecasting with our pan-European market model BID3. The modelling is performed in two steps:

Dispatch (unconstrained)

The market first schedules generation so that supply meets demand at each point in time, assuming the transmission network is capable of sending power wherever it is needed i.e. unconstrained. We approximate this through our dispatch where we schedule generation to meet demand, whilst minimising cost (which is equivalent to a competitive market where generators charge their marginal cost). This can also be thought of as merit order dispatch. This provides us with a forecast of the market solution at gate closure where there are no transmission network bottlenecks.

Redispatch (constrained)

If the transmission network were unconstrained then the market would be allowed to dispatch as it saw fit. However, constraints on the transmission network mean that generation sometimes must be restricted in some areas of the network to satisfy boundary constraints and increased elsewhere to balance supply and demand. This duty is performed by the NESO at minimum cost, and it is this activity that we seek to approximate through the redispatch. BID3 therefore takes the unconstrained dispatch as a starting point and redispatches generation such that demand is met in all zones on the network, and all boundary constraints are respected. The solver adjusts the positions such that the cost of doing so is minimised. All of the usual constraints present in a dispatch run are also present in the redispatch, such as start-up and no-load times on generators.

Total constraint costs measure the cost of redispatching plant from the market equilibrium to a configuration which respects constraints on power flows within the network. BID3 performs this via a cost minimisation algorithm. Total constraint costs can then be compared to measure the effects of reinforcements and of changing generation or demand configurations. Forming this metric over the whole of the GB network and examining the problem as a whole, is essential since the Main Integrated Transmission System (MITS) is interconnected and relieving constraints in one area of the country may cause problems elsewhere. However, it is important to both NESO and our stakeholders to be able to identify where issues are on the grid, and therefore be able to provide a narrative, and the logic behind the results. To provide this an additional feature has been added to BID3 where constraint costs can be allocated by boundary. Sometimes constraint costs can never truly be attributed to a single boundary, for example where a zone is interconnected with many other zones in a group as opposed to radially. However, an indication of where constraints are occurring can be provided by allocating constraint costs by boundary.

Within BID3 the NESO specifies three boundary capability (MW) values for each time-period modelled and where applicable in both directions as determined by power system study. These are thermal capability, voltage capability and stability capability. This recognises that the capability of a boundary may be limited in different seasons and time periods by different electrical restrictions. Practically BID3 will only accept the minimum of these three numbers as the limiting capability in the optimisation, in a particular direction. For avoidance of doubt the NESO models the defined and reverse capability of a boundary, where it exists as two separate boundaries each with their own minimum in the optimisation function.

The total constraint cost used to solve a transmission congestion issue is associated with the bid and offer components within the balancing mechanism. The ‘bid’ is a volume of energy at a £/MWh to reduce generation in an area; and the ‘offer’ is the associated £/MWh to replace the energy in another area of the system.

The model then considers the power flow restrictions on the network and redispatches generation where necessary to relieve instances where power transfer is greater than capability. The costs associated with moving away from the economic dispatch of generation is called the operational constraint costs and is calculated using the bid price and offer price (£/MWh).

The Present Value (PV) of constraint costs attributable to the new interconnector or OHA is calculated by subtracting the system-wide constraint costs without the new interconnector or OHA from the constraint costs with the new interconnector or OHA. The interpretation of a negative number here means that the interconnector or OHA reduces constraints on the network whereas positive numbers represent an increase in constraint costs.

- We modelled each of the nine interconnector and OHA projects for the First Additional and Marginal Additional cases, for each of the three FES22 scenarios used for the analysis.
- For FES22 the last year we are able to model is 2042 as the granular FES data necessary to forecast constraint costs is only available in a 20-year period: for any years after 2042 we use an average of the last three years, i.e. the average of 2040, 2041 and 2042. This is our standard approach for long term constraint cost modelling.
- By undertaking runs with the interconnector or OHA present (the factual), and an identical run except the interconnector or OHA is not present (the counterfactual), we are able to quantify the impact on constraint costs of each interconnector or OHA project.

Constraint Reduction Factor (CRF)

The original constraint cost analysis published in March 2024 highlighted that for certain projects the additional constraint costs due to the inclusion of the project could be significant. NESO’s long term network planning activities, such as the current Transitional Centralised Strategic Network Plan (TCSNP) and the future Centralised Strategic Network Plan (CSNP) planning processes aim to deliver the optimal balance of network reinforcements and constraint costs. Stakeholders stated that the additional constraint costs shown in the original March 2024 report were overstated because in fact NESO would recommend additional reinforcements that would reduce future additional constraint costs. A full justification of the Constraint Reduction Factor as a response to stakeholder feedback can be seen in Ofgem's Window 3 decision document.

To quantify the potential reduction in additional constraint costs, NESO undertook a review of the levels of savings modelled in the Beyond 2030[6] network development plan and compared them to the total cost of the recommended onshore reinforcements. This enabled a Constraint Reduction Factor (CRF) to be calculated. That is, for every £1 billion of additional constraint costs identified after a set date, this can be discounted by a fixed percentage. A unique CRF was calculated for each FES, as each one has a unique mix of reinforcements in its optimal reinforcement path, as well as a unique level of reduction in constraint costs when the reinforcements are applied. Based on feedback from the Transmission Owners (TOs), the CRF was only applied from 2035 onwards, as the TOs are likely to be able to provide new reinforcements over and above existing identified options after that date.

The Constraint Reduction Factors applied post-2035 were 69%, 79% and 68% for Leading the Way, Consumer Transformation and Falling Short respectively. Hence with the CRF applied for LW, every additional £1bn of total GB constraint costs identified across the whole system after 2035 will be reduced to £310m. The resultant impact of the CRF on each individual project will vary across the projects, as well as across the scenarios. This is because the level of additional constraint costs for each Cap and Floor Window 3 project varies from year to year and hence will be affected to varying degrees by the discounting process.

The results are shown without and with the Constraint Reduction Factor applied. The results without the CRF applied represent a worst case, ie no additional reinforcements are identified and delivered by the TOs over and above those already included within NESO's latest TCSNP. The results with the CRF applied may represent a best case, based on historic levels of constraint cost reduction per additional reinforcement spend. The actual additional constraint cost level may well fall between the without CRF and with CRF levels, hence we have presented both sets of results. In addition, by presenting the additional constraint costs without and with the CRF it is possible to identify the reduction in additional constraint costs solely due to the CRF.

Limitations of constraint cost modelling

To undertake the constraint cost analysis requires the NESO to have the relevant suite of network reinforcements that form an output of the Transitional Centralised Strategic Network Plan (TCSNP) process. Although the FES23 were released in mid-2023, it was not possible to use them for the analysis published in March 2024 as the TCSNP process output would not be available until early 2024. In theory, as the Beyond 2030 network analysis, which uses FES23 as an input became available in March 2024 it could have been used for this latest analysis. However, this would have made comparison to the original Cap and Floor analysis published in March 2024 difficult as the outputs would have been based on two separate sets of FES. Hence the modelling undertaken by the NESO for this report has used three of the FES22 scenarios: Leading the Way, Consumer Transformation and Falling Short, using the optimal network from HND1 / NOA 2021/22 Refresh[7] and incorporating the modifications mentioned previously.

The constraint cost results in this section represent a view of future constraint costs based on the FES used and the associated reinforcements that are currently scheduled to be constructed and non-network solutions that will become operational at the same time as the applicant interconnector and OHA projects. An increase in constraint costs provide a signal for the need for further network reinforcements, or non-network solutions. Our future planning processes will provide an assessment of when such solutions would deliver economic benefit, whilst considering the impact on community, environmental and operability. The cost of reinforcing the network is expected to be lower than the additional constraint costs shown but estimating the required reinforcement

[6] Beyond 2030 | National Energy System Operator

[7] The Holistic Network Design (HND) provides a recommended offshore and onshore design for a 2030 electricity network, that facilitates the Government's ambition for 50GW of offshore wind by 2030. The NOA 2021/22 Refresh is an update to the NOA 2021/22 that was published in January 2022 in accordance with standard condition C27 of the NESO transmission licence. It integrates the HND's offshore network and confirms the wider onshore network requirements.

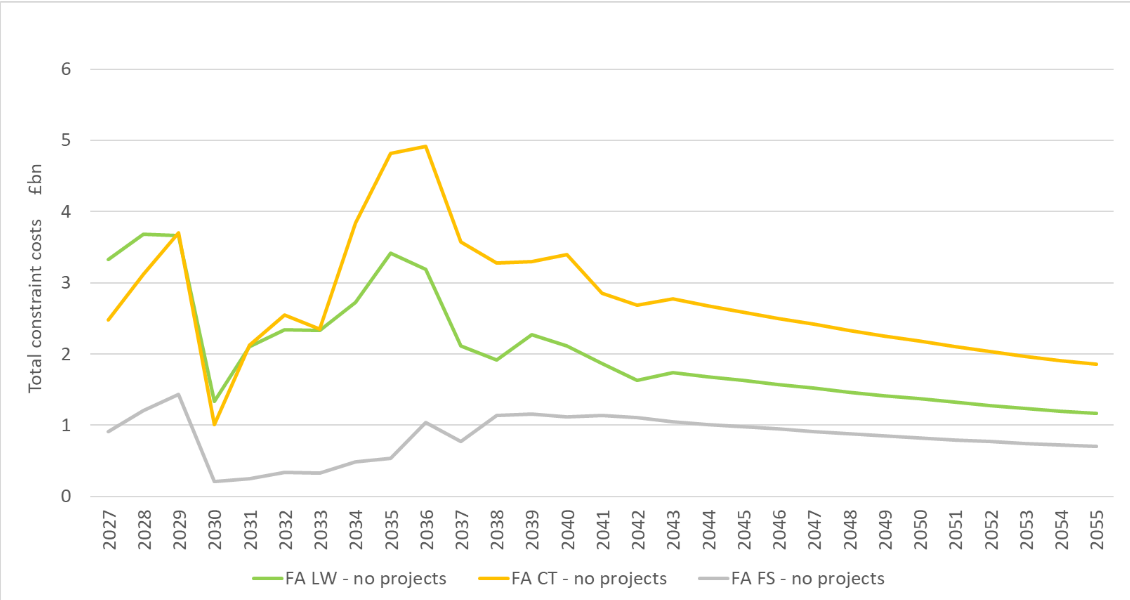
costs to mitigate the additional constraint costs attributable to the W3 and OHA projects is difficult as each reinforcement is unique in terms of cost, network capability and timing. It is also important to note that NESO does not recommend network reinforcement by considering one project in isolation: NESO will recommend a suite of reinforcements based on a holistic assessment of future developments in demand and supply.

Results

Placing the results in context- Comparison of interconnector constraint costs to total GB constraint costs

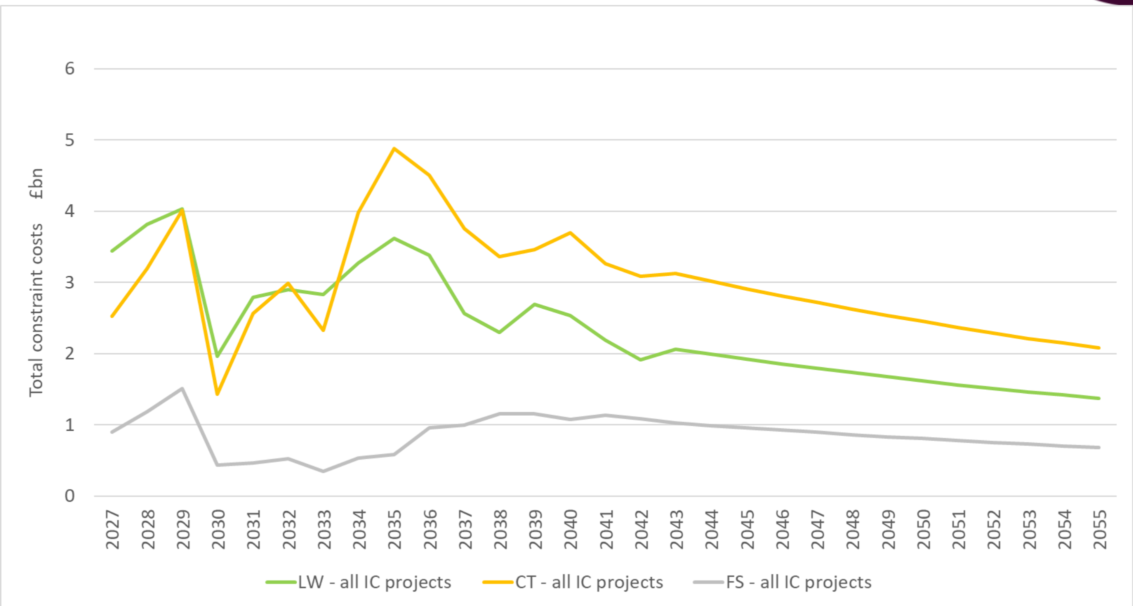
This section provides some context on the constraint cost modelling undertaken and the high-level results. To calculate the impact of each project on constraint costs, we used our pan-European market model: this can calculate total annual constraint costs for GB.

Figure 1: Annual total constraint costs for the three FES, with none of the nine interconnector or OHA projects included.



The above figure shows the level of constraint costs if none of the nine interconnector and OHA projects under consideration are included. This is the counterfactual for the First Additional case. Our pan-European market model can only model out to 2042, so after this point the results are an average of the previous three years. The annual results are discounted to enable the net present value to be calculated, hence annual constraint costs decrease for years further in the future. Note that no Constraint Reduction Factor has been applied.

Figure 2: Annual total constraint costs for the three FES, with all the nine interconnector and OHA projects included.

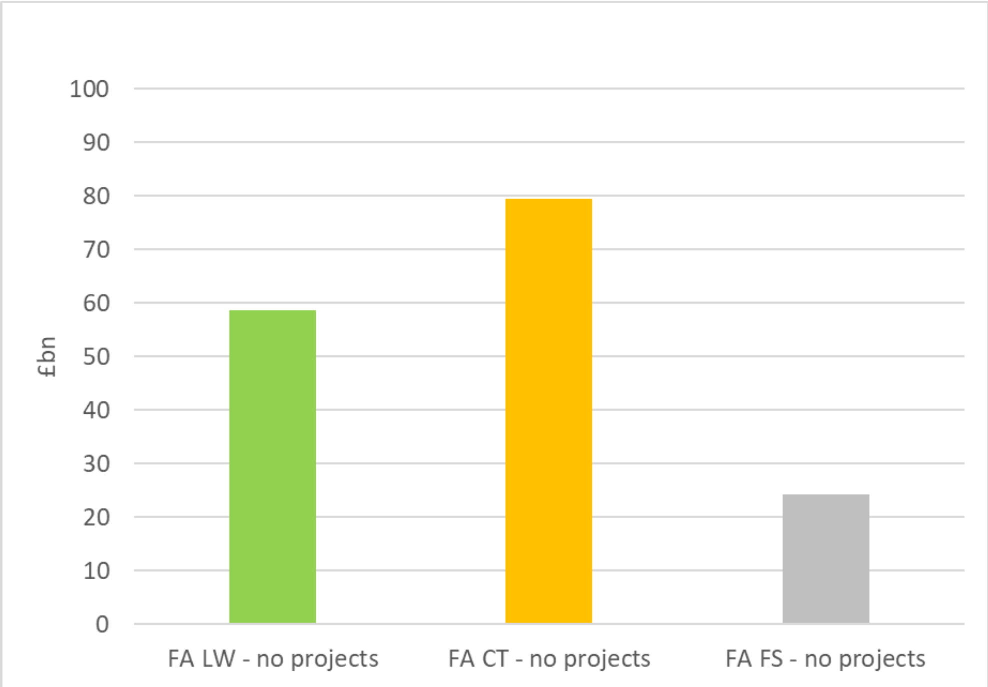


The above figure shows annual total constraint costs for the three scenarios modelled, for the period 2027 to 2055 if all the nine projects under consideration are included. Note that no Constraint Reduction Factor has been applied.

Figure 1 and

Figure 2 can be converted to provide a single total constraint cost in Present Value terms for the period 2027 to 2055 for each scenario for the First Additional and Marginal additional cases. This is shown in the following two figures.

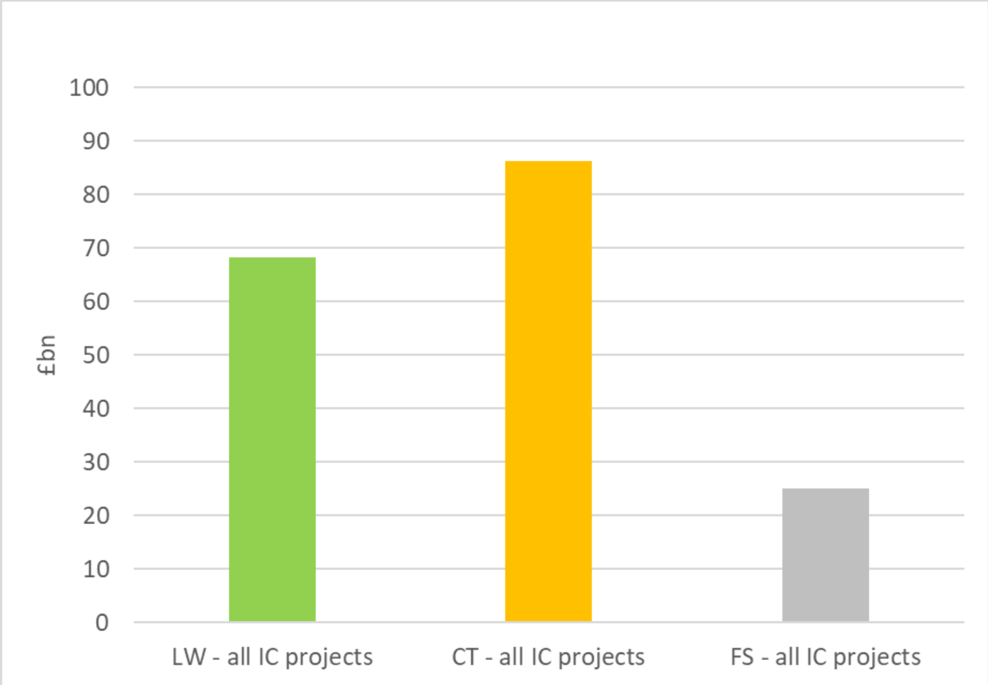
Figure 3: Total constraint costs for the three FES for the period 2027 to 2055, PV, real 2022, £bn, with none of the projects included.



The above figure shows total constraint costs when none of the projects are included. The above figure shows that total constraint costs for the period 2027 to 2055 range from between approximately £24 billion to £80 billion.

Public

Figure 4: Total constraint costs for the three FES for the period 2027 to 2055, PV, real 2022, £bn with all the projects included.

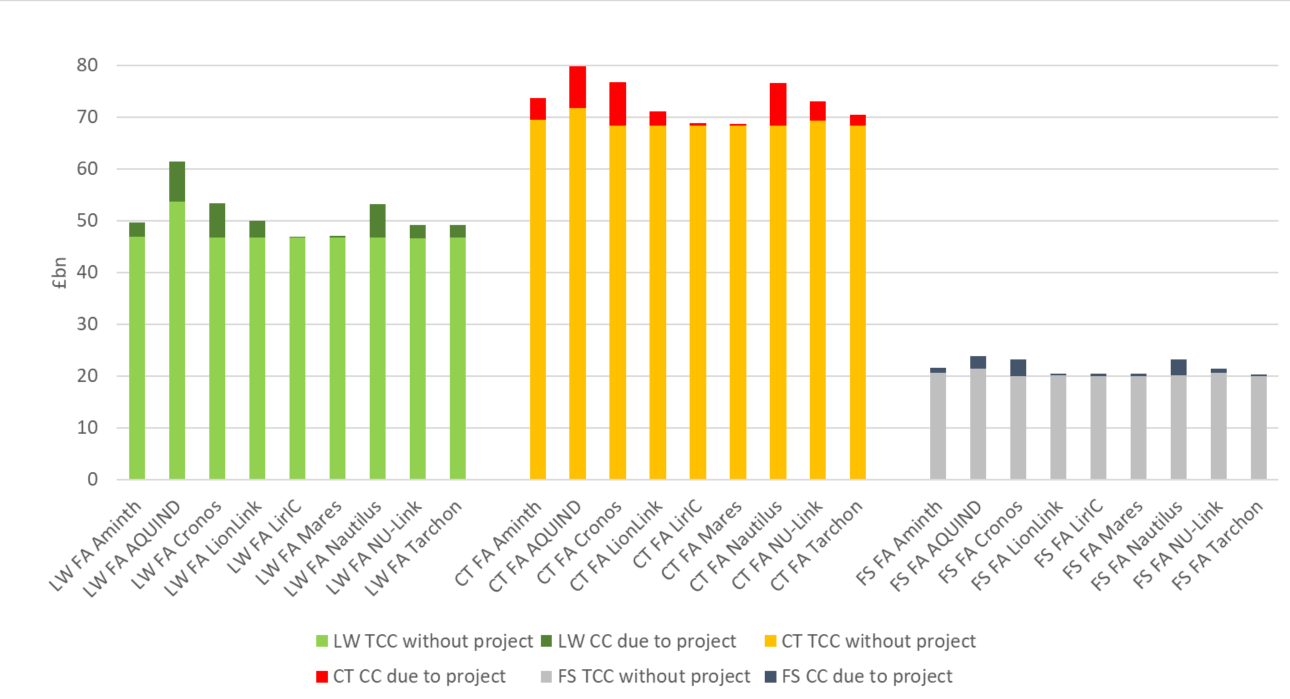


The above figure shows total constraint costs when all nine projects are included. The above figure shows that total constraint costs for the period 2027 to 2055 range from between approximately £25 billion to £86 billion.

The difference in total constraint costs for the period 2027 to 2055 when all the nine projects are included and when none of the nine projects are (i.e. the difference between Figure 4 and Figure 3) is £9.6 billion, £6.8 billion and £690 million for Leading the Way, Consumer Transformation and Falling Short respectively.

For the First Additional case, we modelled the impact on constraint costs when each of the nine projects is added individually. The results can be seen in the following chart.

Figure 5: Total constraint costs for the First Additional case, PV, 25-years, real 2022, £bn.

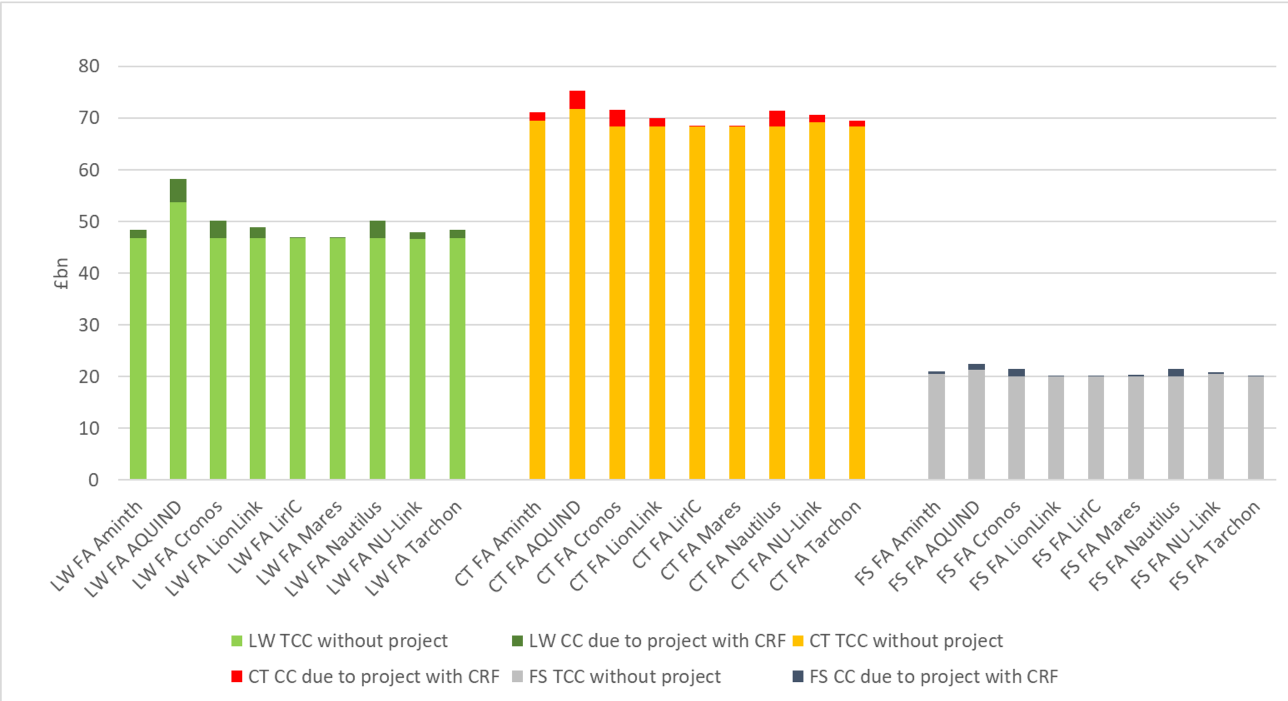


The nine bars for each scenario show the total constraint costs for each project. The lighter coloured section of the bar represents the constraint costs when the project is not included[8]: the darker coloured section (e.g. the red element for CT) represents the additional constraint costs due to the particular project when it is included. The darker coloured section represents the additional constraint costs that are solely due to the inclusion of that project. The height of lighter coloured section for each bar varies across projects because of the variation in start dates for the nine projects.

The above chart shows that the additional constraint costs due to each of the nine projects represents a relatively small part of the total constraint costs, although in absolute terms the additional constraint costs can be significant, for example approximately £8 billion over the lifetime of the interconnector.

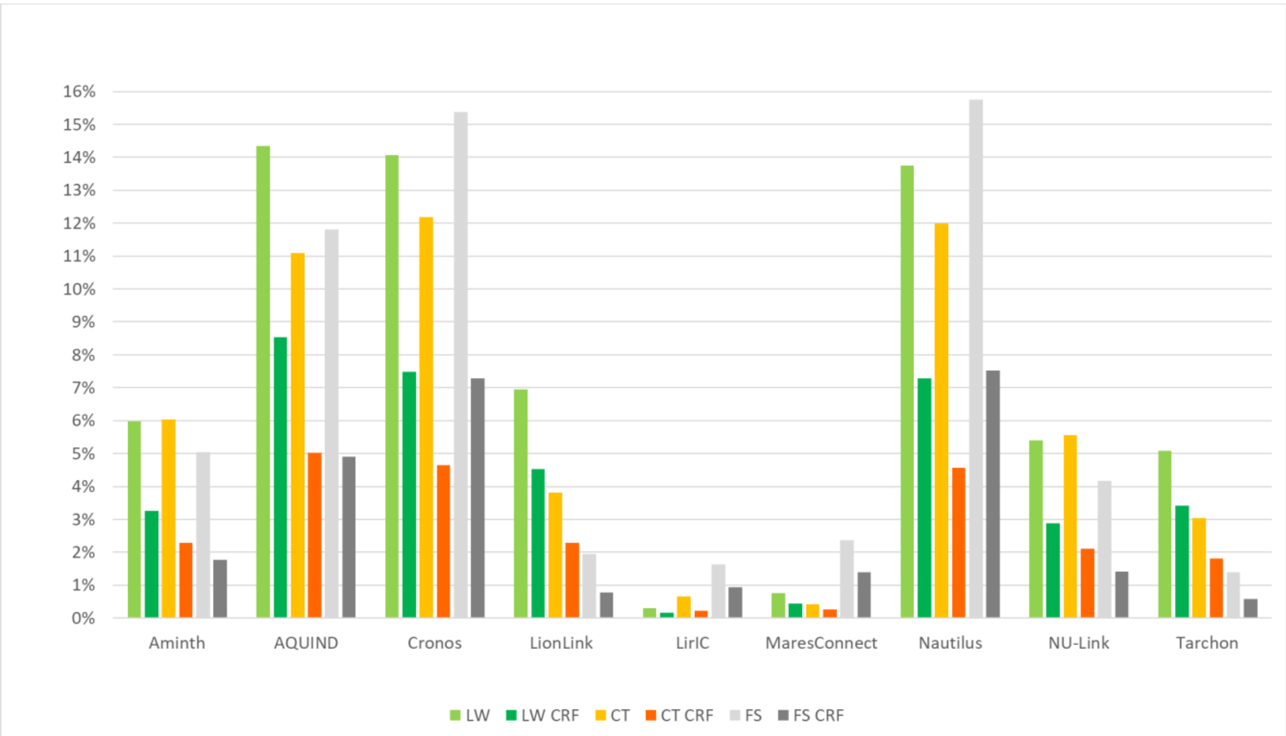
[8] Note: the size of the lighter coloured bars in Figure 5 are lower than those in Figure 3. This is because Figure 3 is for the period 2027 to 2055, whereas Figure 5 shows the relevant 25-year period for each project depending on their commissioning date.

Figure 6: Total constraint costs for the First Additional case with Constraint Reduction Factor applied, PV, 25-years, real 2022, £bn.



The chart above shows the impact on additional constraint costs when the Constraint Reduction Factor is applied. The Constraint Reduction Factor has a material impact on the additional constraint costs due to the inclusion of the project. The chart below compares the percentage increase in constraint costs for the First Additional case, without and with the CRF.

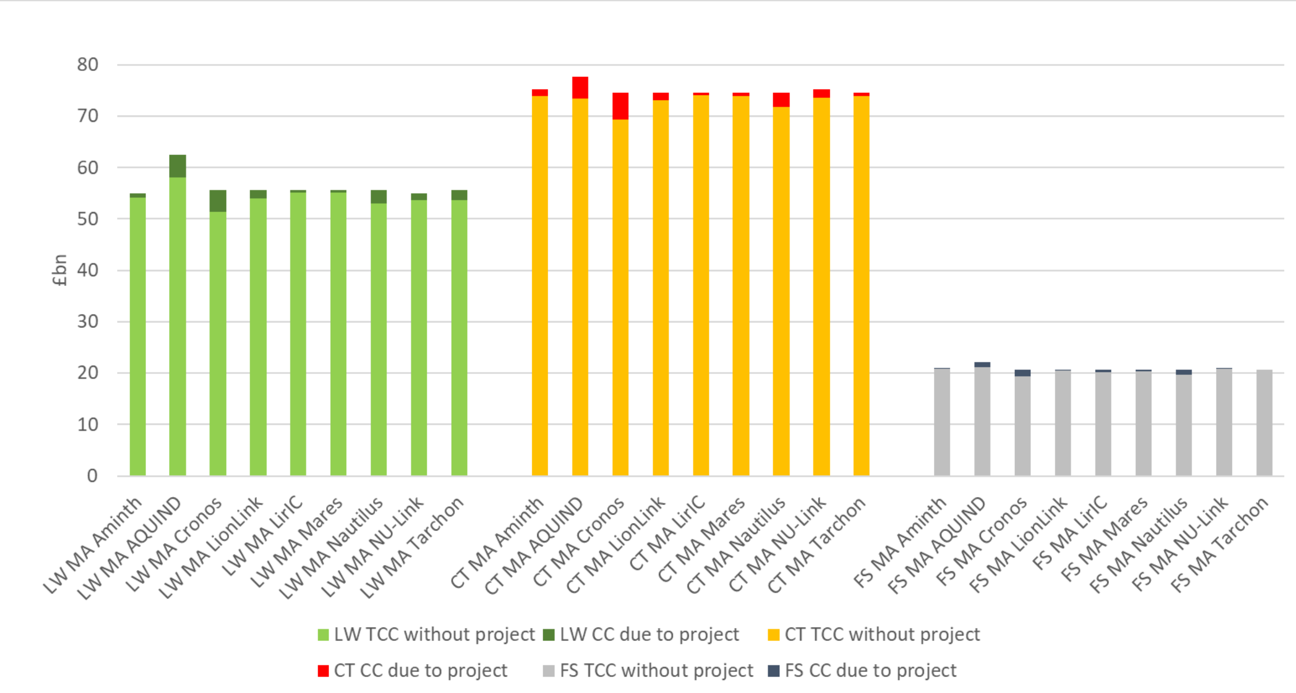
Figure 7: Percentage increase in constraint costs, without and with Constraint Reduction Factor for the First Additional case.



The chart above shows that the percentage reduction in additional constraint costs due to the inclusion of the CRF can be significant, for example for AQUIND in the Leading the Way scenario, additional constraint costs are reduced from approximately 14% to 8.5%.

For the Marginal Additional case, we modelled the impact on constraint costs when each of the nine projects is removed individually. The results can be seen in the following chart.

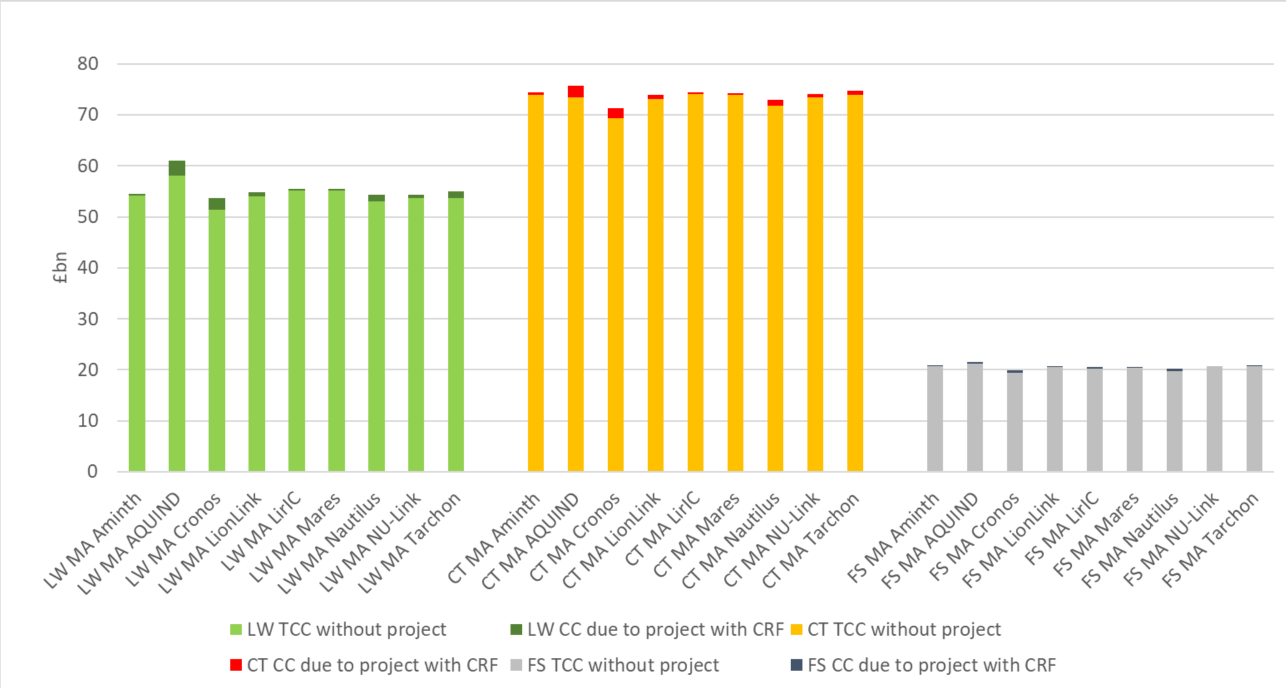
Figure 8: Total constraint costs for the Marginal Additional case, PV, 25-years, real 2022, £bn.



The nine bars for each scenario show the total constraint costs for each project. The lighter coloured section of the bar represents the constraint costs when the project is not included but the other eight Cap and Floor Window 3 projects are: the darker coloured section (e.g. the red element for CT) represents the additional constraint costs due to the particular project when it is included. The darker coloured section represents the additional constraint costs that are solely due to the inclusion of that project. The height of the lighter coloured section of each bar varies across projects because of the variation in start dates for the nine projects.

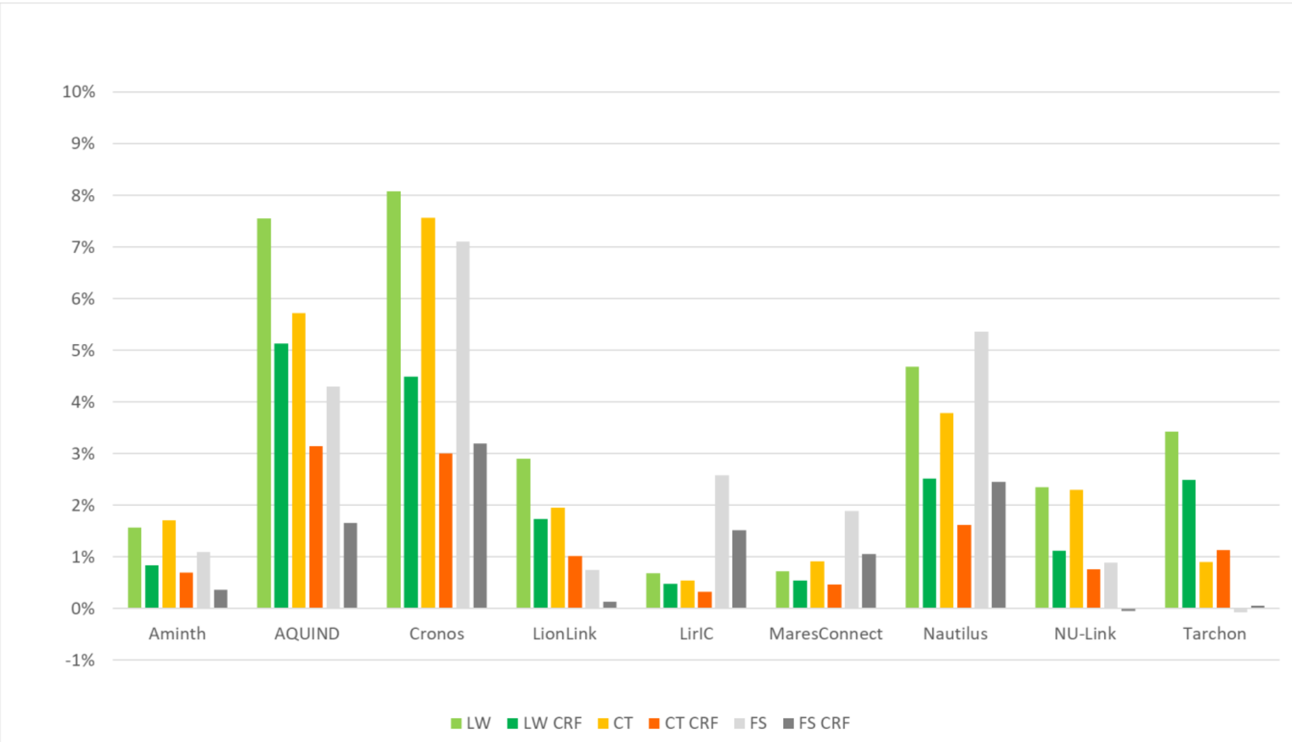
The above chart shows that the additional constraint costs due to each of the nine projects represents a relatively small part of the total constraint costs, although in absolute terms the additional constraint costs can be significant, for example approximately £5 billion over the lifetime of the interconnector.

Figure 9: Total constraint costs for the Marginal Additional case with the Constraint Reduction Factor applied, PV, 25-years, real 2022, £bn.



The chart above shows the impact on additional constraint costs when the Constraint Reduction Factor is applied. The chart shows that the inclusion of the Constraint Reduction Factor has a material impact on the additional constraint costs due to the inclusion of the project. The chart below compares the percentage increase in constraint costs for the Marginal Additional case, without and with the CRF.

Figure 10: Percentage increase in constraint costs, without and with Constraint Reduction Factor for the Marginal Additional case.



The chart above shows that the percentage increase in constraint costs, ie the additional constraint costs due to a particular project is lower in the MA case than the FA case. The reduction in additional constraint costs due to the CRF is still significant, for example for AQUIND in the Leading the Way scenario, additional constraint costs are reduced from approximately 7.5% to 5%.

Figure 5 and Figure 8 show that the increase in additional constraint costs is higher in the First Additional case than in the Marginal Additional case. This is to be expected, as the interconnector baseline is higher in the MA case, as all the other eight Cap and Floor Window 3 projects are already included. Hence the balancing actions are spread across a larger number of interconnectors.

FA Results

This section shows the results for the constraint cost modelling for the First Additional case. The results are shown without the Constraint Reduction Factor applied, showing the impact of the updates to the scenarios, and with the CRF applied. Hence the impact of only the scenarios updates can be compared to the combined impact of scenario updates and the CRF.

The following table shows the results when the Constraint Reduction Factor is not applied.

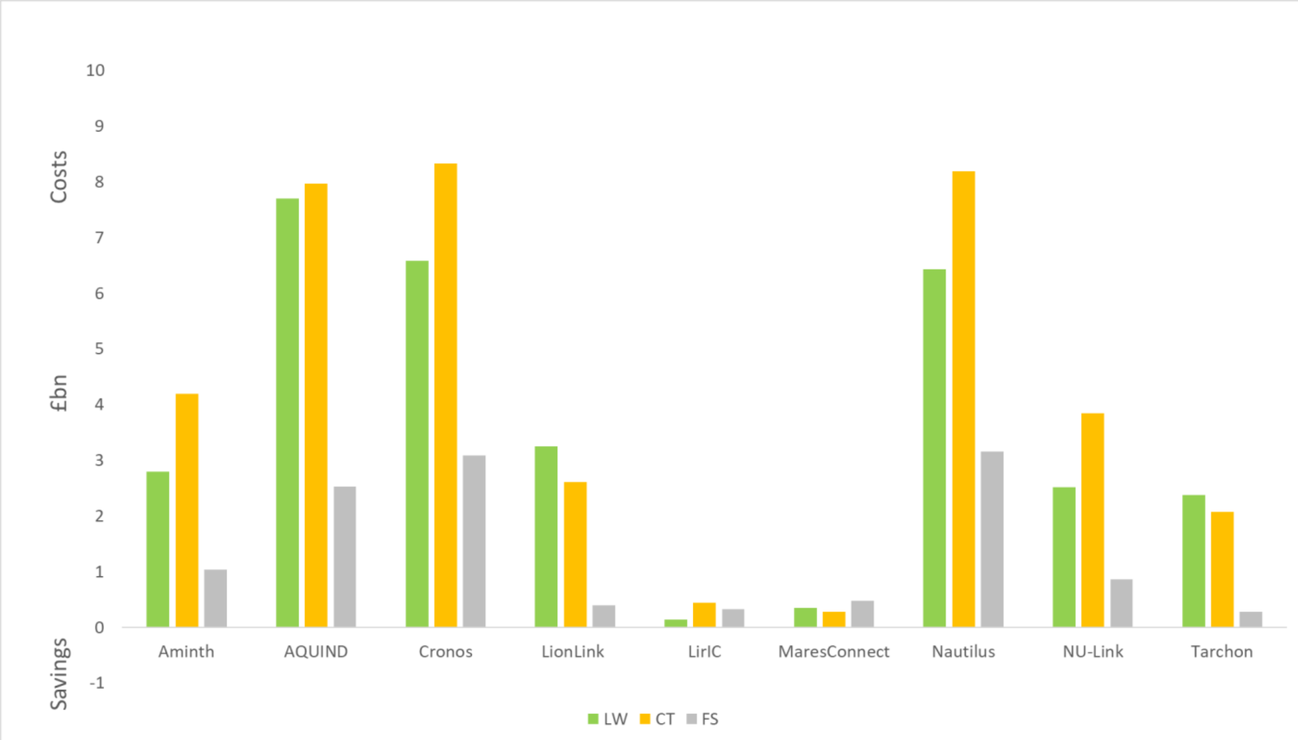
Table 2: change in constraint costs due to the addition of each interconnector and OHA for the First Additional (FA) case.

NPV, real 2022, £bn, +ve = additional costs	LW	CT	FS
Aminth	2.80	4.19	1.04
AQUIND	7.71	7.97	2.52
Cronos	6.58	8.33	3.09
LionLink	3.25	2.61	0.39
LirIC	0.14	0.45	0.33
MaresConnect	0.35	0.28	0.47
Nautilus	6.43	8.19	3.16
NU-Link	2.52	3.85	0.86
Tarchon	2.37	2.07	0.28

The table above shows the change in constraint costs in Present Value[9] (PV) terms for each of the nine projects for the First Additional case, for each of the three FES scenarios without the Constraint Reduction Factor applied. Positive numbers represent an increase in constraint costs and negative numbers represent a constraint saving. The figure below shows the same results but in chart format.

[9] Present Value, also known as present discounted value, is the value today (or some other specified date) of a future amount of money. For example, the PV constraint costs shown in this report show the present value of 25 years of constraint costs in 2022 GB pounds.

Figure 11: change in constraint costs due to the addition of each interconnector and OHA for the First Additional case, PV, 25 years, real 2022, £bn.



The figure above shows that there is a wide variation in the change in constraint costs. None of the projects result in a constraint saving: all of the interconnector and OHA pilot projects result in an increase in constraint costs. There is considerable variation in the increase in constraint costs from one project to another. Differences in constraint costs will be due to a range of factors. Firstly, the location of the interconnector in GB is important, as certain locations will be in more constrained parts of the network. Secondly, the magnitude and direction of flows across the interconnector will have a direct impact on the scale of the constraint actions that need to be taken to achieve a supply demand match that conforms to network capabilities.

Increases in constraint costs are highest in the Leading the Way and Consumer Transformation scenarios. These are driven by the higher levels of renewable generation in these two scenarios resulting in higher price differentials in the two connected markets driving higher flows across the interconnector or OHA and consequently higher constraint management actions.

The highest increase in additional constraint costs in the First Additional case, i.e. when only one of the Cap and Floor Window 3 projects is included, is approximately £8.3bn. This represents approximately a 12% increase in total constraint costs over the 25-year period compared to total constraint costs when the project is not included.

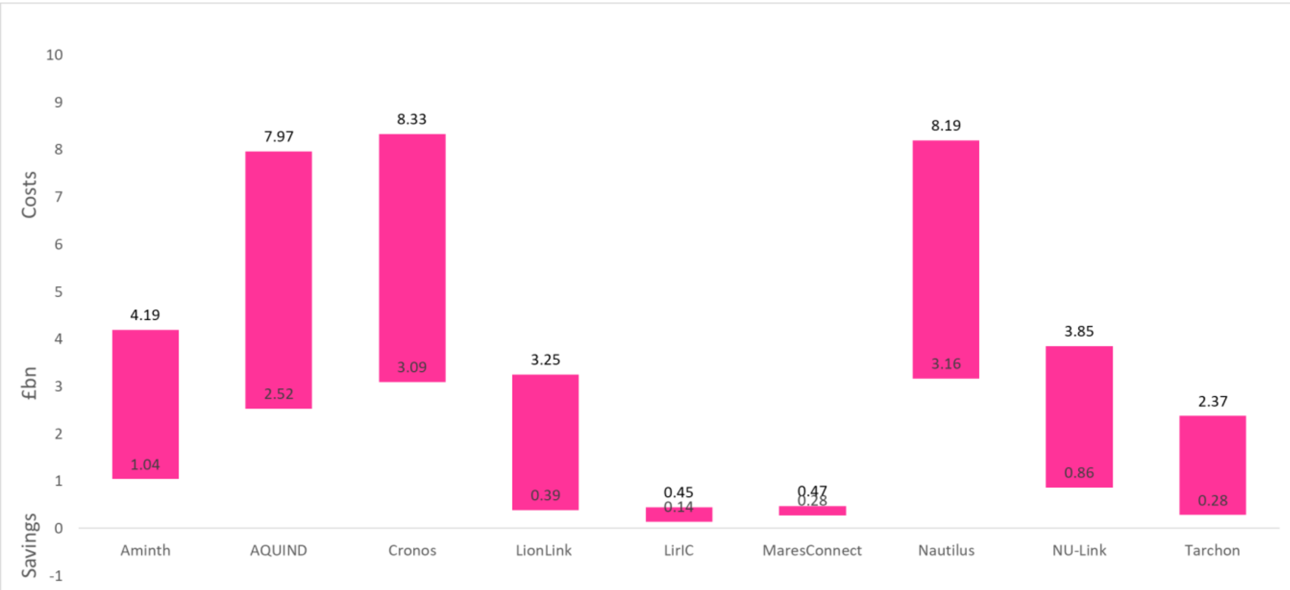
The flow patterns across interconnectors will vary depending on the connecting country, driven by the market fundamentals in GB and the connected country. Export flows across the W3 interconnectors or OHA pilot projects may lead to increased flows in constrained parts of the GB network, leading to an increase in constraint management actions.

Previous analysis undertaken by the NESO, such as the analysis to support Ofgem's third Cap and Floor Window and OHA pilot regulatory framework[10] has highlighted how the location of an interconnector or OHA

[10] https://www.ofgem.gov.uk/sites/default/files/2022-08/ESOTargetingAnalysis.pdf

and the import and export flows for the project can have a significant impact on whether a project will cause an increase or decrease in total constraint costs. The analysis has shown that only interconnectors connecting to Northern England or Scotland and that are exporting for the majority of the time will reduce overall constraint costs, as they will be helping to reduce north to south flows across GB and hence reduce balancing actions. Any interconnector or OHA that connects in the Midlands or southern England and that is exporting for most of the time is likely to lead to increased constraint costs as more balancing actions will need to be taken to relieve constraints across various boundaries.

Figure 12: range of change in constraint costs due to the addition of each interconnector and OHA for the First Additional case, PV, 25 years, real 2022, £bn.



The figure above shows the range across the three scenarios (LW, CT and FS) of the change in constraint costs for each interconnector and OHA. The size of the range varies significantly between projects.

The following table shows the results for the First Additional case with the Constraint Reduction Factor applied.

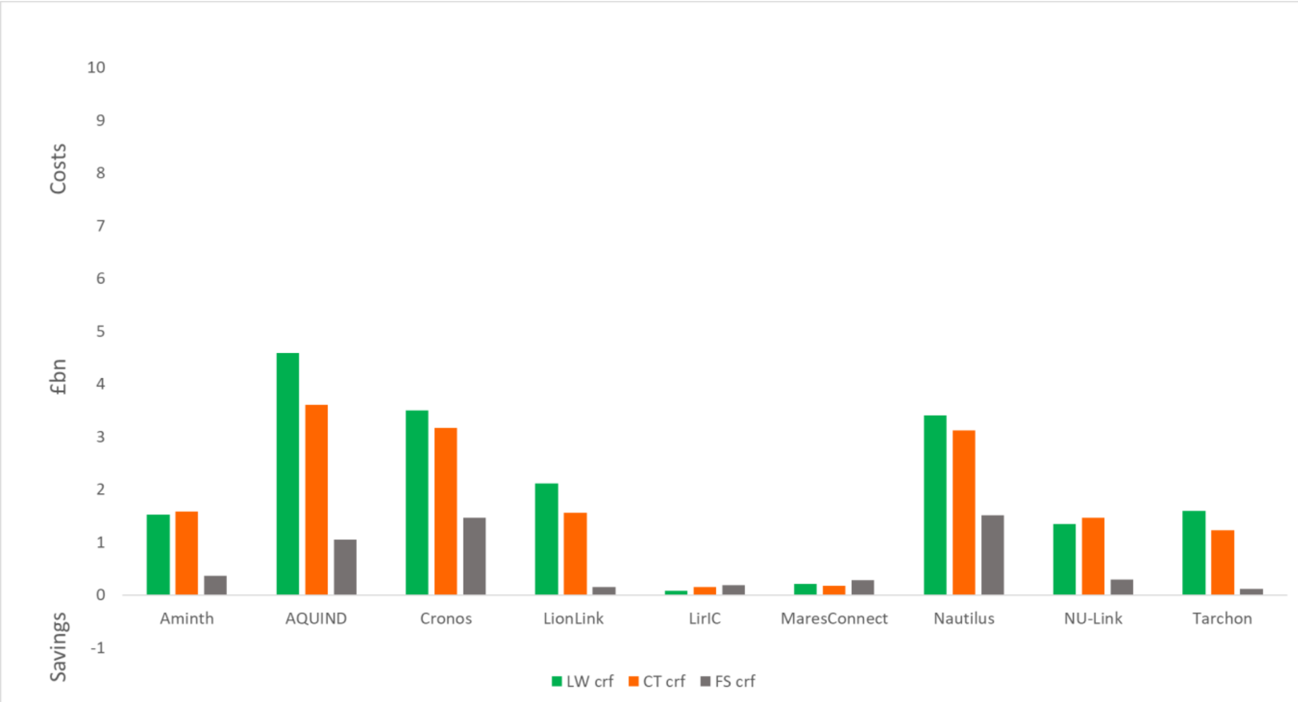
Table 3: change in constraint costs due to the addition of each interconnector and OHA for the First Additional (FA) case, with Constraint Reduction Factor applied.

NPV, real 2022, £bn, +ve = additional costs	LW CRF	CT CRF	FS CRF
Aminth	1.52	1.58	0.36
AQUIND	4.59	3.60	1.05
Cronos	3.50	3.17	1.46
LionLink	2.11	1.56	0.16
LirIC	0.08	0.15	0.19
MaresConnect	0.21	0.17	0.28
Nautilus	3.41	3.12	1.51
NU-Link	1.35	1.46	0.29
Tarchon	1.60	1.23	0.12

The above table shows significant reductions in additional constraint costs compared to Table 2.

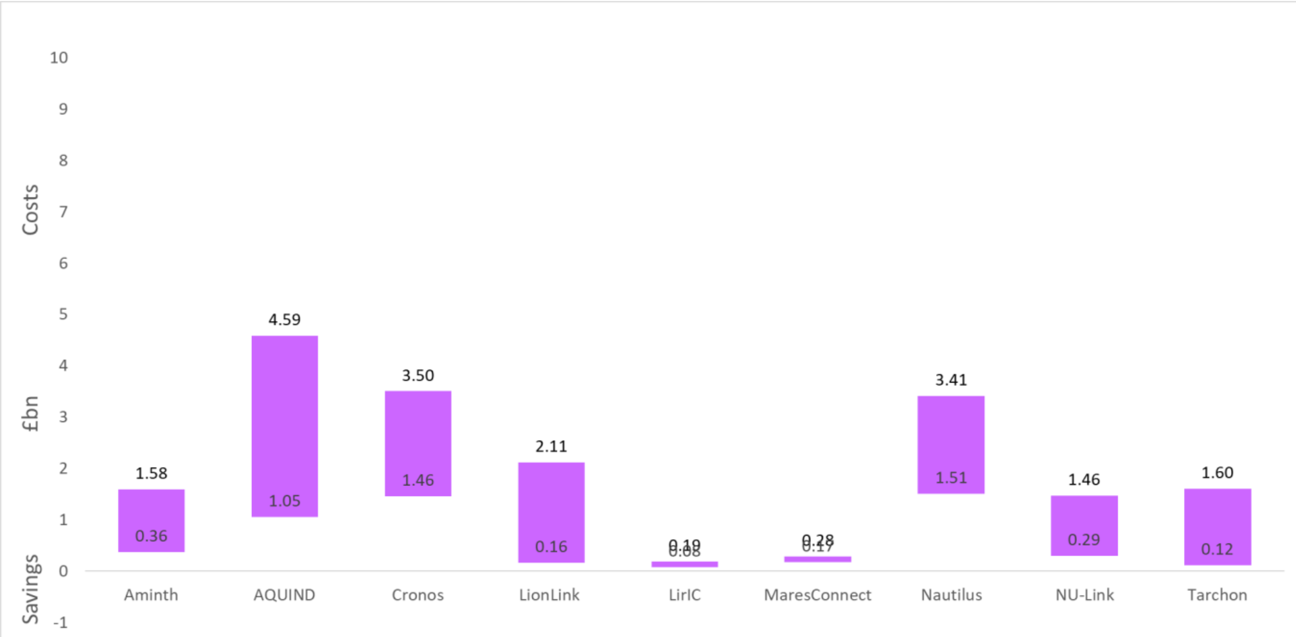
The figure below shows the same results but in chart format.

Figure 13: change in constraint costs due to the addition of each interconnector and OHA for the First Additional case, PV, 25 years, real 2022, £bn, with Constraint Reduction Factor applied.



The figure below shows the range across the three scenarios (LW, CT and FS) of change in constraint costs for each interconnector and OHA with the CRF applied.

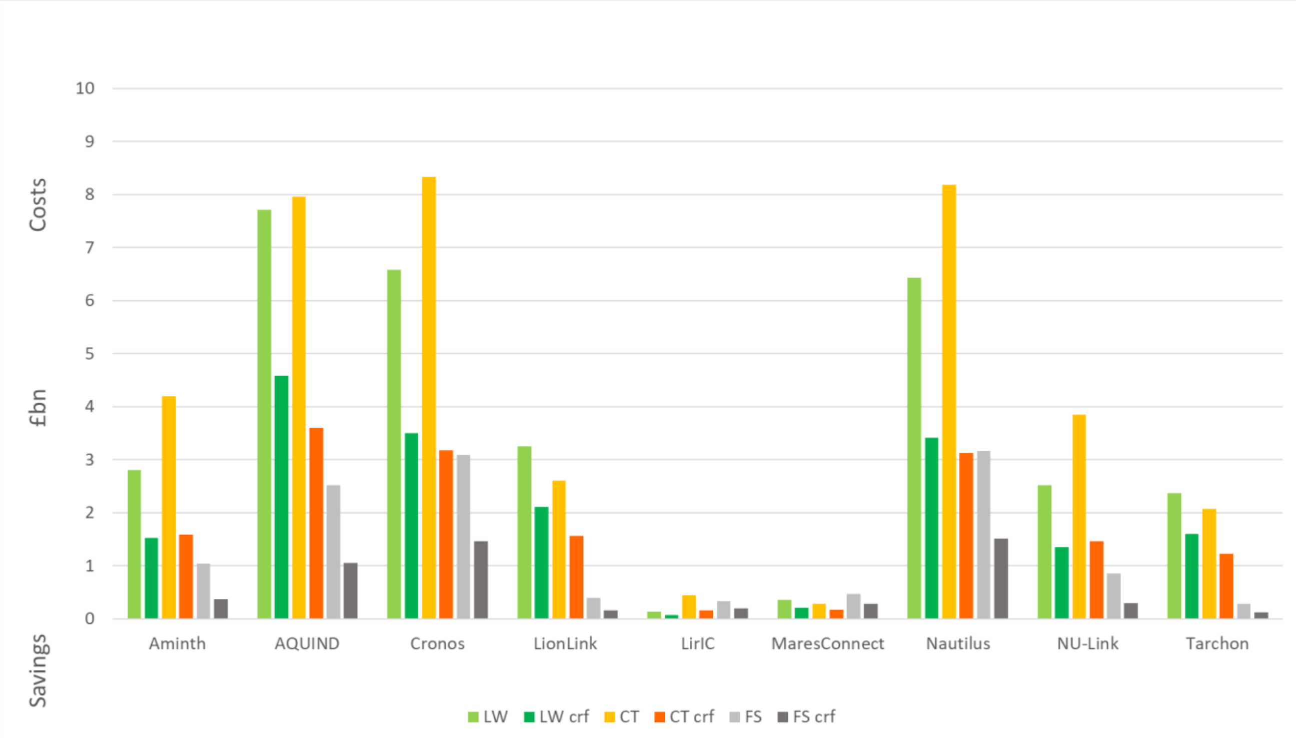
Figure 14: range of change in constraint costs across the three scenarios due to the addition of each interconnector and OHA for the First Additional case, PV, 25-years, real 2022, £bn, with Constraint Reduction Factor applied.



The figure above shows that there is considerable variation in the range of additional constraint costs across the three scenarios for each project.

The figure below compares the change in additional constraint costs for each project without and with the Constraint Reduction Factor applied for the First Additional case.

Figure 15: change in constraint costs due to the addition of each interconnector and OHA for the First Additional case, PV, 25 years, real 2022, £bn, without and with the Constraint Reduction Factor applied.

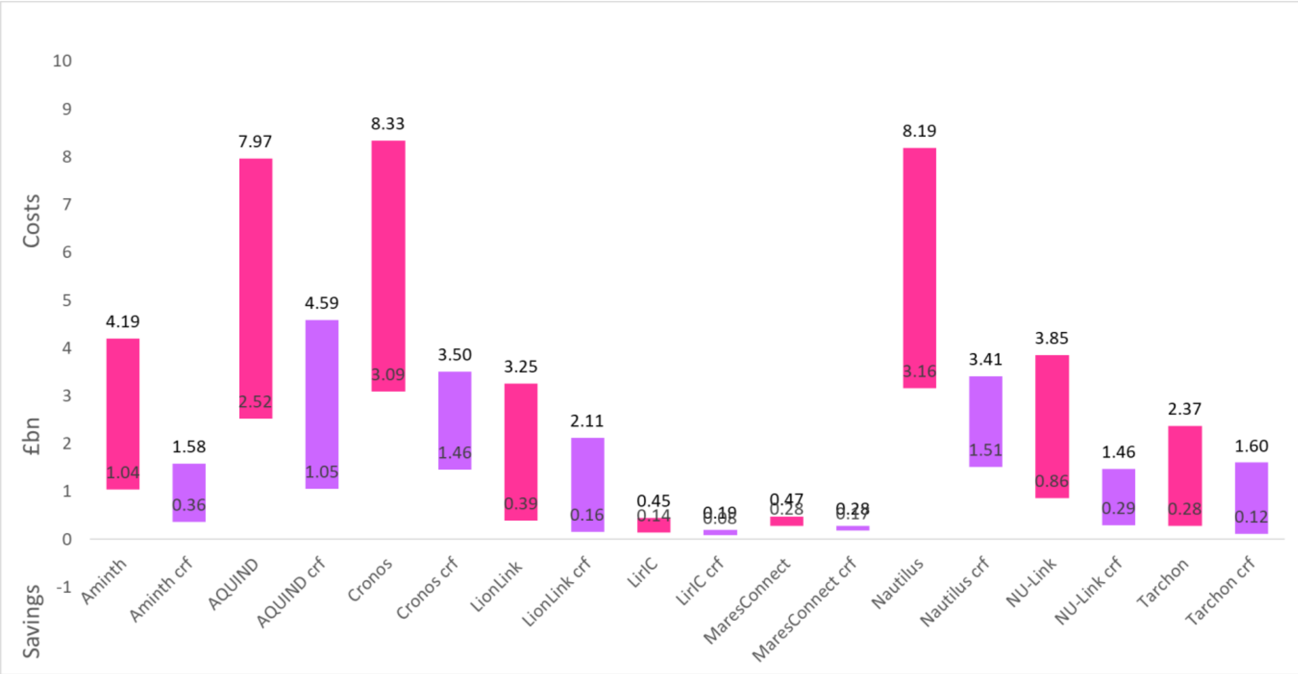


The figure above shows the additional constraint costs for each project for each scenario for the First Additional Case, without and with the CRF applied. When the CRF is applied, as expected there is a significant reduction in additional constraint costs.

Note that the percentage reduction for each project will vary, even though the same CRF has been applied for each project for a given scenario. This is due to several factors, including different commissioning dates, different constraint cost profiles across the years and the level of the additional constraint costs in the years 2040, 2041 and 2042, as these years form the average constraint cost that is extrapolated out for the remainder of each projects assumed 25-year life expectancy. This effect can be seen more clearly in the annual constraint cost charts for each individual project in sections 10 to 18 of this report.

The following chart shows the range of change in constraint costs for the First Additional case, without and with the Constraint Reduction Factor applied.

Figure 16: range of change in constraint costs across the three scenarios due to the addition of each interconnector and OHA for the First Additional case, PV, 25-years, real 2022, £bn, without and with Constraint Reduction Factor applied.

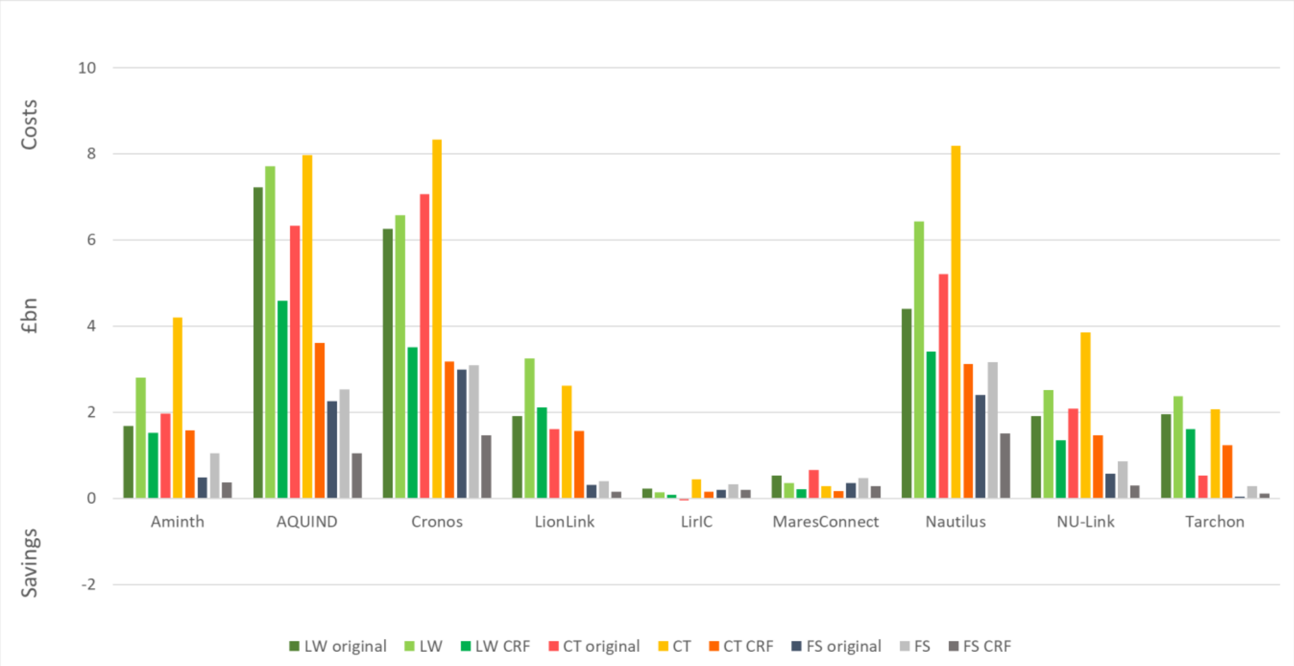


The figure above highlights that although the CRF significantly reduces additional constraint costs there is still a wide variation in additional constraints across the three scenarios and across the nine projects.

The chart below shows the comparison of the latest modelling for the First Additional case to the original results published in March 2024[11]. The latest modelling is shown without and with the Constraint Reduction Factor.

[11] The original NESO (formerly ESO) modelling report, published in March 2024 is available at: https://www.ofgem.gov.uk/sites/default/files/2024-03/ESO%20CF%20W3%20Report%20-%20Final.pdf

Figure 17: change in constraint costs due to the addition of each interconnector and OHA for the First Additional case, PV, 25 years, real 2022, £bn, for the original analysis (March 2024) and for Nautilus at Grain with 1.4GW link plus Irish demand and generation from TYNDP2022, without and with CRF.



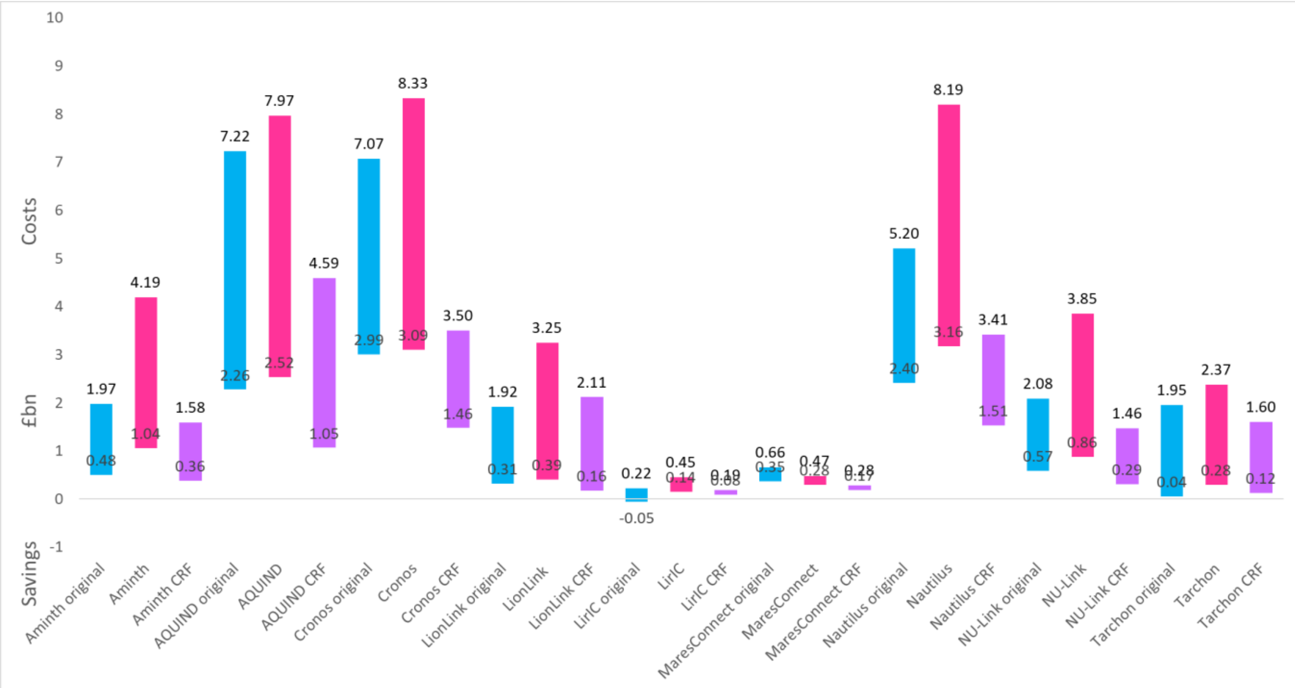
The above figure shows that additional constraint costs are higher in the latest modelling without the CRF compared to the modelling undertaken in March 2024, for all projects in all scenarios except for LirIC and MaresConnect. The increases are most pronounced in Consumer Transformation but are also significant in Leading the Way for several projects. LirIC and MaresConnect show a reduction in additional constraint costs for Leading the Way. MaresConnect also shows a reduction in additional constraint costs in Consumer Transformation.

The latest results with the CRF show a significant reduction in additional constraint costs compared to the latest results without the CRF and also in some instances when compared to the original (March 2024) results. AQUIND and Cronos for Leading the Way and Consumer Transformation show this clearly. For other projects, such as Aminth and LionLink for Leading the Way, the additional constraint costs in the latest modelling with CRF are similar to those for the original modelling.

For the FA case, the changes to Irish demand and generation in the latest scenarios results in an increase in imports and a decrease in exports for LirIC and MaresConnect. The impact of the changes on the other projects varies. AQUIND, Cronos, NU-Link and Tarchon show little change in annual import and export flows, whereas Aminth, LionLink and Nautilus show a reduction in imports and an increase in exports. Import and export flows are shown for each individual project in sections 10 to 18 of this report.

Changes in the levels of additional constraint costs are not directly linked to changes in the levels of annual import and export flows on the project. This is clearly shown with the results for MaresConnect, where all three scenarios show an increase in imports and a decrease in exports in the latest modelling compared to the original (March 2024) modelling, whereas additional constraint costs decrease in the LW and CT scenarios and increase in FS, when no CRF is applied. The changes in additional annual constraint costs is driven by the summation of all the individual additional constraint costs modelled at a 3 hour resolution across each year of the simulation. The additional constraint costs will be driven by a combination of factors including the location of the project, the network capacity and the level of the flows across the project in the dispatch. These factors drive the supply demand solution for the relevant scenario and subsequent resultant balancing actions in the redispatch.

Figure 18: Additional constraint cost range, for the original (March 2024) analysis, and for the latest analysis, without and with Constraint Reduction Factor for the First Additional case.



The above chart highlights the wide variation in additional constraint costs across the scenarios for certain projects. Nautilus shows the largest increase in range in the latest modelling without CRF.

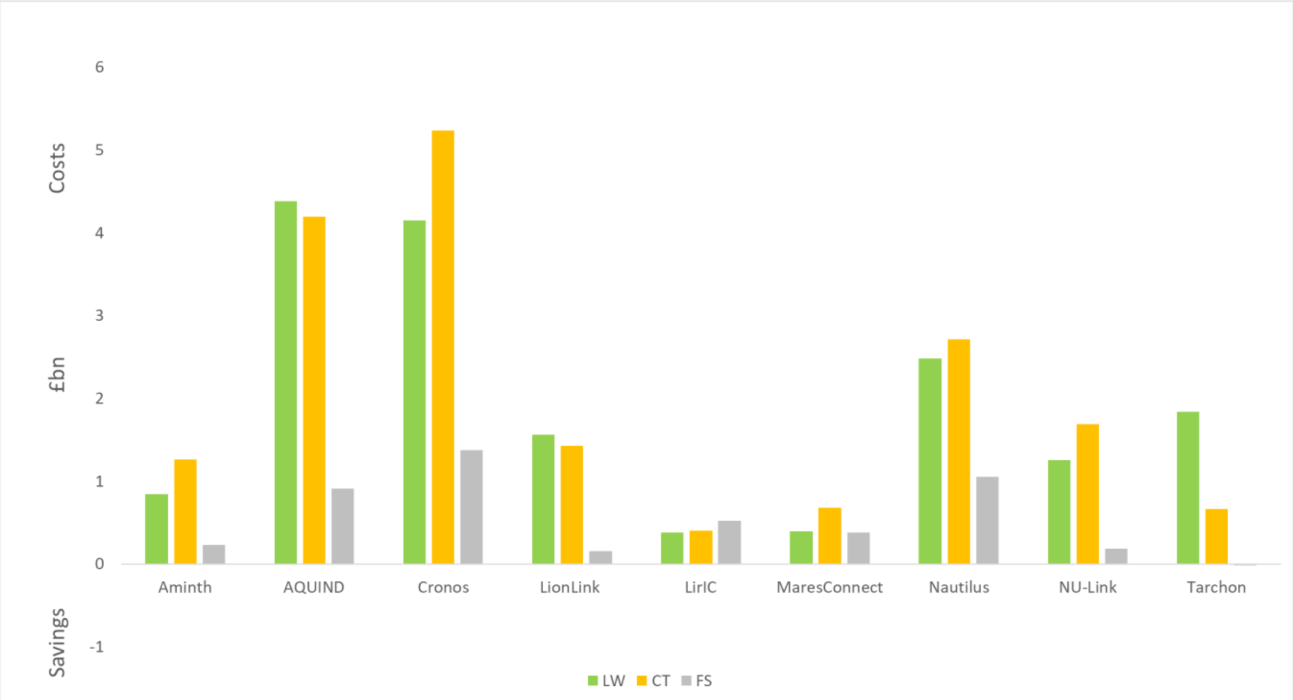
MA Results

Table 4: change in constraint costs due to the addition of each interconnector and OHA for the Marginal Additional case.

NPV, real 2022, £bn, +ve = additional costs	LW	CT	FS
Aminth	0.85	1.26	0.23
AQUIND	4.39	4.20	0.91
Cronos	4.15	5.24	1.37
LionLink	1.56	1.43	0.15
LirIC	0.38	0.40	0.52
MaresConnect	0.39	0.68	0.38
Nautilus	2.48	2.71	1.05
NU-Link	1.26	1.69	0.18
Tarchon	1.84	0.67	-0.02

The table above shows the change in constraint costs in Present Value (PV) terms for each of the nine projects for the Marginal Additional case, for each of the three FES, without the Constraint Reduction Factor applied. Positive numbers represent an increase in constraint costs and negative numbers represent a constraint saving. The figure below shows the same results but in chart format.

Figure 19: change in constraint costs due to the addition of each interconnector and OHA for the Marginal Additional case, PV, 25 years, real 2022, £bn.



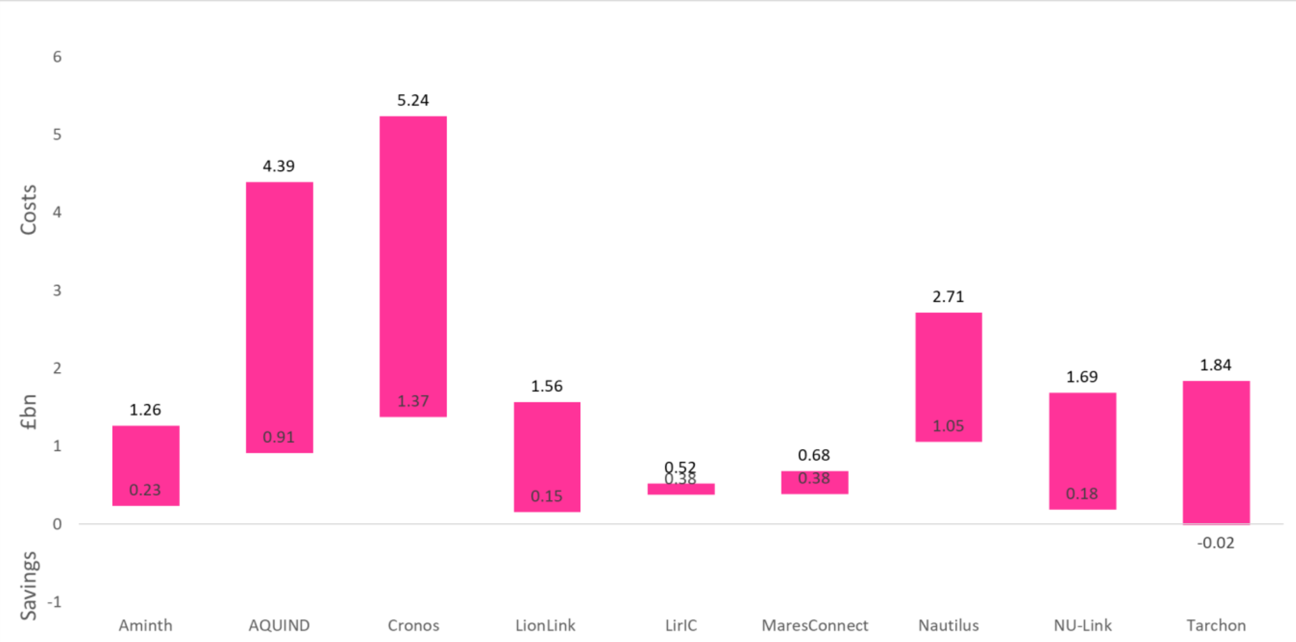
The figure above shows that there is a wide variation in the change in constraint costs. There is only one instance where a project results in constraint savings: Tarchon for the Falling Short scenario and the saving is small. All the other interconnector and OHA pilot projects result in an increase in constraint costs. There is considerable variation in the increase in constraint costs from one project to another. This will be driven by a combination of factors including the location of the project, the network capacity and the impact of the flows across the project in the dispatch driven by the supply demand solution for the relevant scenario and subsequent resultant balancing actions in the redispatch.

Compared to the First Additional case, in general the Marginal Additional case results in lower increases in constraint costs. This is because the inclusion of all the other Cap and Floor Window 3 and OHA pilot projects within the supply demand mix reduces the impact of any one interconnector or OHA on constraint costs.

The highest increase in constraint costs for the Marginal Additional case, i.e. when all of the Cap and Floor Window 3 projects are included, is approximately £5.2bn. This represents approximately an 8% increase in total constraint costs over the 25-year life of the project.

Care should be taken when interpreting the results of Figure 11 and Figure 19. The charts represent the difference in constraint costs of adding a particular W3 interconnector or OHA project, that is the difference in constraint costs between when the project is included and when the project is excluded. Whilst the levels of additional constraint costs of adding one additional W3 project in the Marginal Additional case are lower than in the First Additional case, total constraint costs, that is the total of all the balancing market actions taken in any given year, are higher in the Marginal Additional case, as shown in Figure 5 and Figure 8.

Figure 20: range of change in constraint costs across the three scenarios due to the addition of each interconnector and OHA for the Marginal Additional case, PV, 25-years, real 2022, £bn.



The above figure shows that although the absolute level of additional constraint costs is reduced in the Marginal Additional case, the range, that is the variation across the three scenarios remains high.

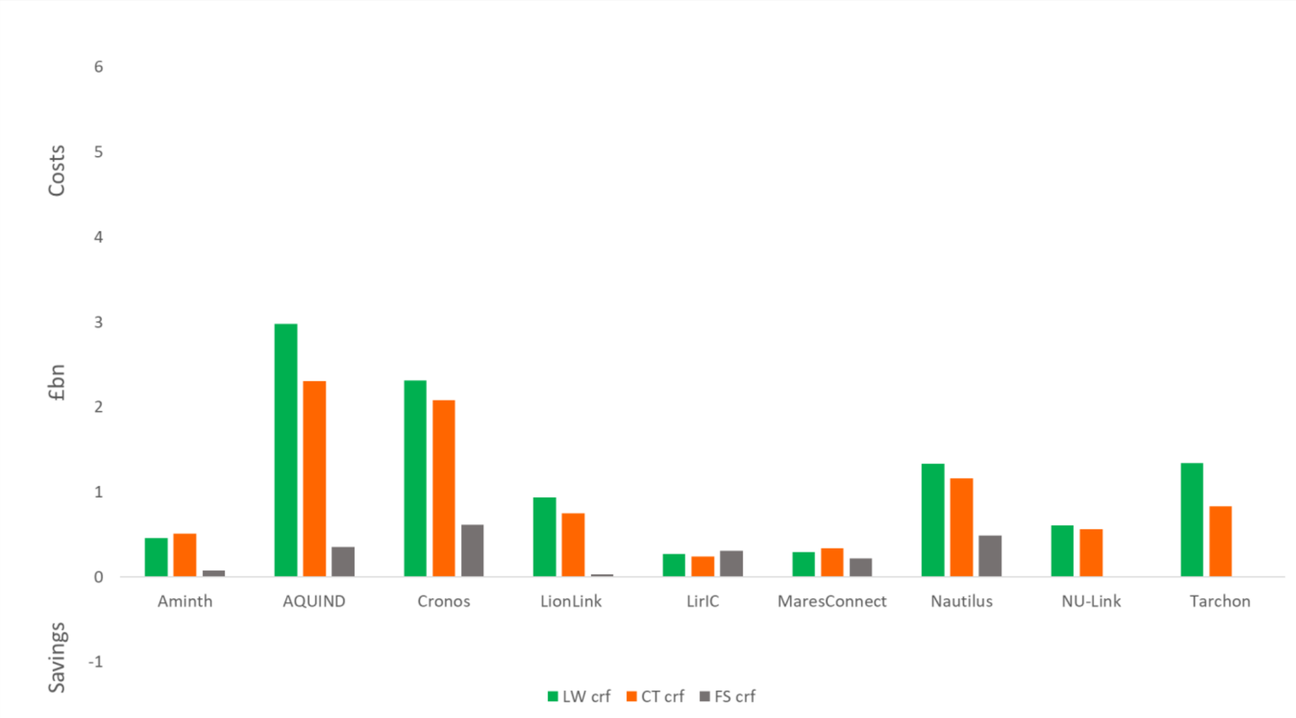
The following table shows the impact of including the Constraint Reduction Factor on the latest modelling of the First Additional case.

Table 5: change in constraint costs due to the addition of each interconnector and OHA for the Marginal Additional case, PV, 25 years, real 2022, £bn, with Constraint Reduction Factor applied.

NPV, real 2022, £bn, +ve = additional costs	LW CRF	CT CRF	FS CRF
Aminth	0.46	0.51	0.07
AQUIND	2.98	2.31	0.35
Cronos	2.31	2.08	0.62
LionLink	0.93	0.75	0.03
LirIC	0.27	0.24	0.31
MaresConnect	0.30	0.34	0.21
Nautilus	1.33	1.16	0.48
NU-Link	0.60	0.56	-0.01
Tarchon	1.34	0.83	0.01

The table above shows that compared to Table 4 the impact of the CRF is significant. The figure below shows the same results but in chart format.

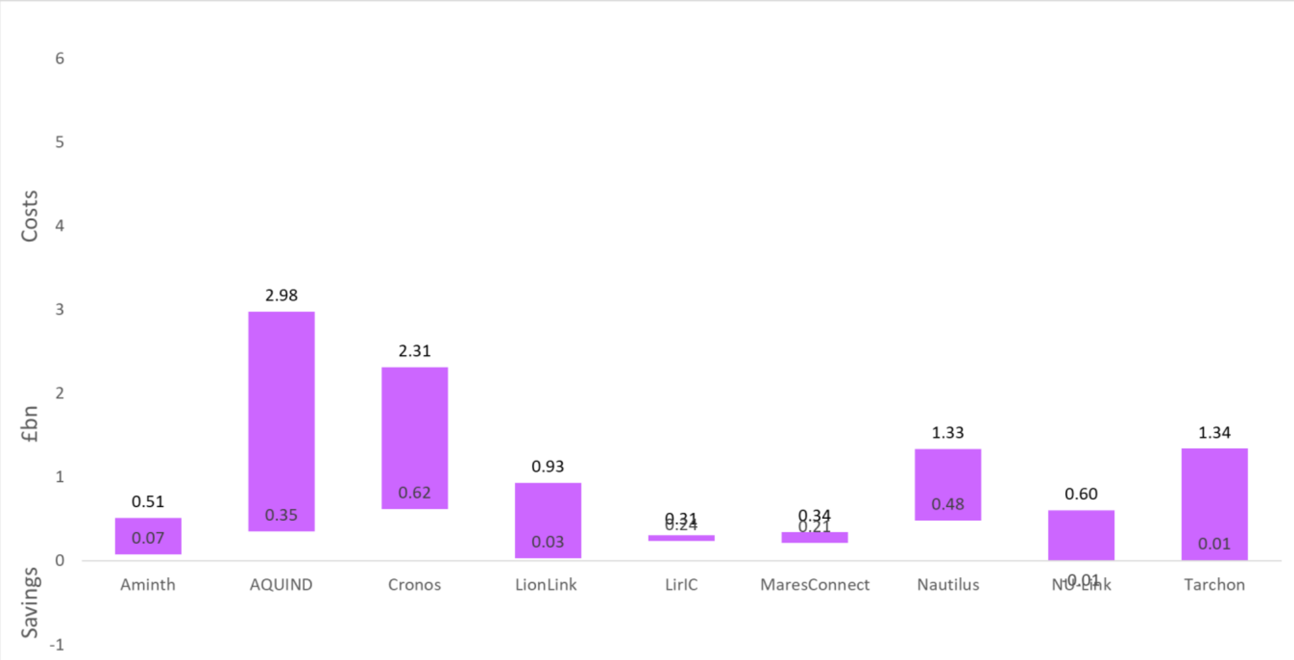
Figure 21: change in constraint costs due to the addition of each interconnector and OHA for the Marginal Additional case, PV, 25 years, real 2022, £bn, with Constraint Reduction Factor applied.



The following chart shows the same data but in the form of ranges.

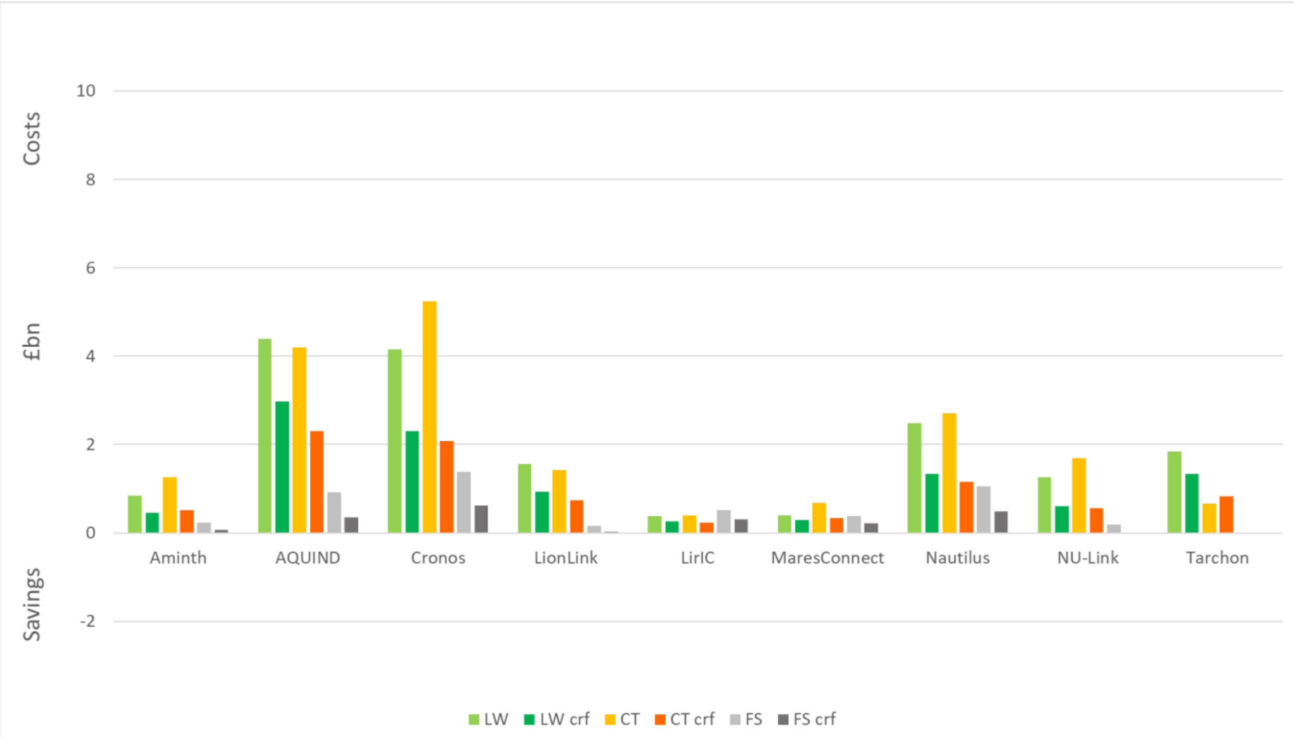
Public

Figure 22: range of change in constraint costs across the three scenarios due to the addition of each interconnector and OHA for the Marginal Additional case, PV, 25-years, real 2022, £bn, with Constraint Reduction Factor applied.



The figure below compares the change in additional constraint costs for each project without and with the Constraint Reduction Factor applied for the Marginal Additional case.

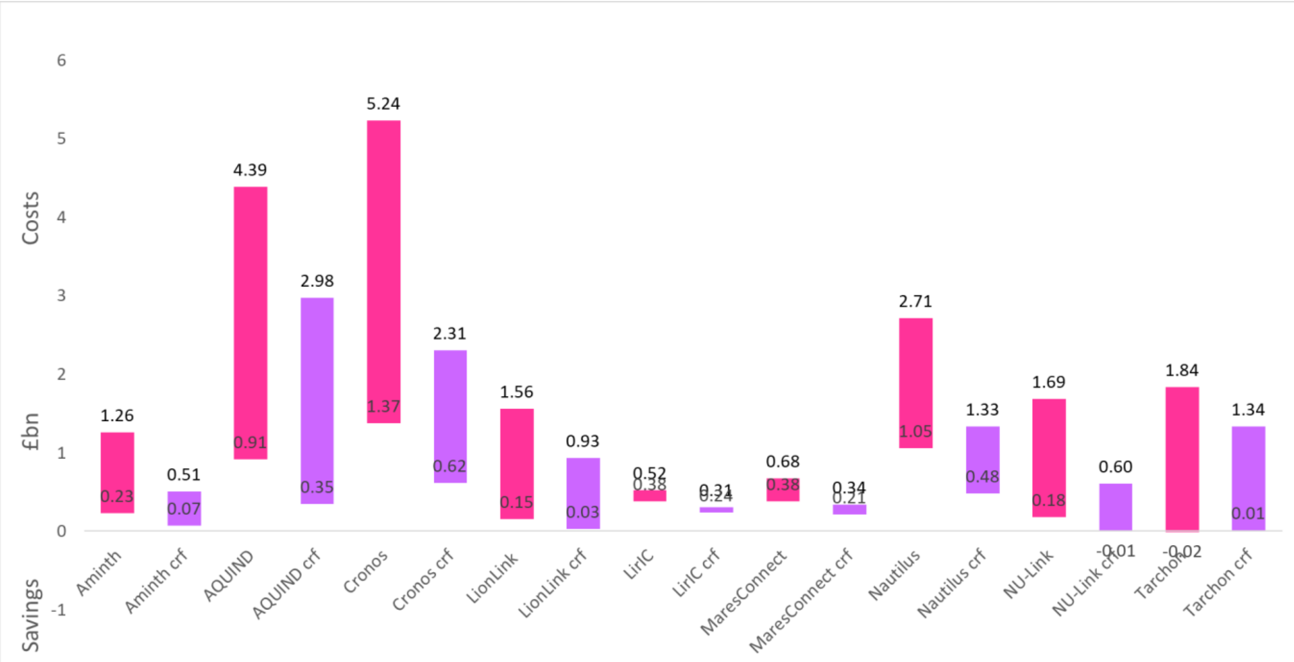
Figure 23: change in constraint costs due to the addition of each interconnector and OHA for the Marginal Additional case, PV, 25 years, real 2022, £bn, without and with the Constraint Reduction Factor applied.



The figure above shows the additional constraint costs for each project for each scenario for the Marginal Additional Case, without and with the CRF applied. When the CRF is applied, as expected there is a significant reduction in additional constraint costs. Note that the percentage reduction for each project will vary, even though the same CRF has been applied for each project for a given scenario.

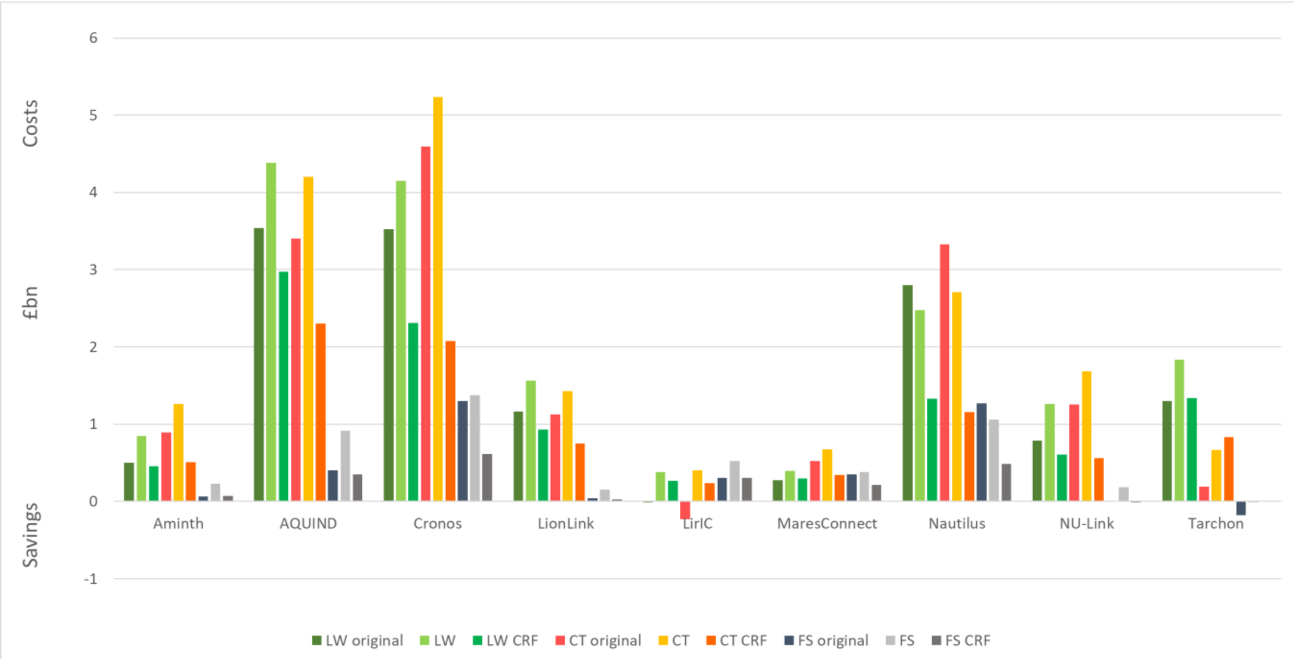
The chart below shows the same data but in terms of ranges.

Figure 24: range of change in constraint costs across the three scenarios due to the addition of each interconnector and OHA for the Marginal Additional case, PV, 25-years, real 2022, £bn, without and with Constraint Reduction Factor applied.



The chart below shows the comparison of the latest modelling for the Marginal Additional case, without and with the CRF, to the original results.

Figure 25: change in constraint costs due to the addition of each interconnector and OHA for the Marginal Additional case, PV, 25 years, real 2022, £bn, for the original analysis (March 2024) and for Nautilus at Grain with 1.4GW link plus Irish demand and generation from TYNDP2022, without and with CRF.



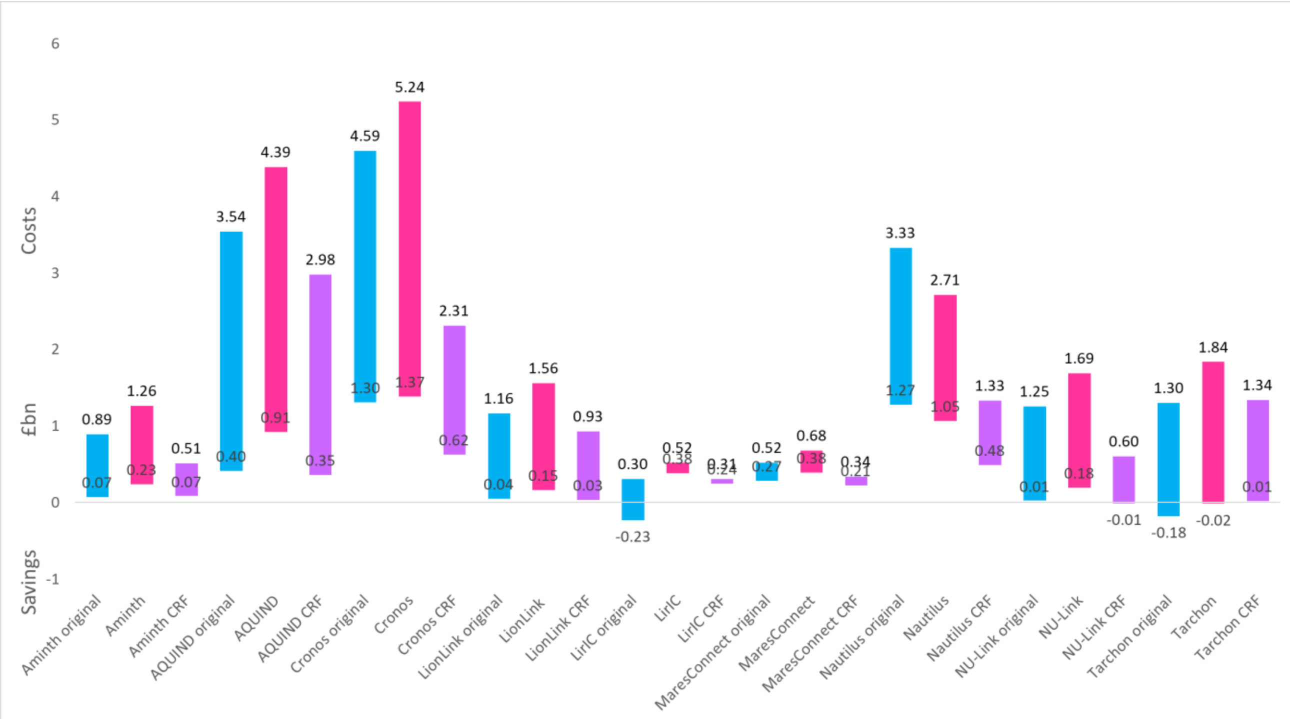
The above figure shows the additional constraint costs are higher in the latest modelling without the CRF compared to the modelling undertaken in March 2024 for all projects for all scenarios, except for Nautilus.

For the MA case, the changes to Irish demand and generation in the latest scenarios results in an increase in imports and a decrease in exports for LirIC and MaresConnect. Nautilus shows a reduction in imports and exports compared to the original modelling. The impact of changes on flows on the other projects is less pronounced than in the FA case. This is to be expected as the MA case includes all the other Cap and Floor Window 3 projects in the background and hence the level of impact of any one interconnector or OHA is reduced. Aminth, and LionLink show an increase in exports and a decrease in imports. Many of the other project show similar levels of annual import and export flows as those seen in the original analysis. The import and export flows across each of the Cap and Floor Window 3 projects are shown in the **Results by Project** chapters.

The latest results with the CRF show a significant reduction in additional constraint costs compared to the latest results without the CRF and also in some instances compared to the original (March 2024) results. Cronos for Leading the Way and Consumer Transformation shows this clearly.

As with the FA modelling, changes in levels of additional constraint costs are not directly linked to changes in the levels of annual import and export flows on the project. The changes made to the scenarios, such as the change in demand and generation in Ireland results in complex changes in flows in the dispatch and subsequent balancing actions undertaken in the redispatch.

Figure 26: Additional constraint cost range, for the original (March 2024) analysis and the latest analysis, without and with Constraint Reduction Factor for the Marginal Additional case.



The above chart highlights the wide variation in additional constraint costs across the scenarios for certain projects. The impact of the scenarios changes in the latest modelling without CRF results in a higher range, except for Nautilus. The impact of the inclusion of the CRF is very pronounced for certain projects such as Cronos and Nautilus and less so in others, such as LionLink and Tarchon.

Summary of FA and MA changes in constraint costs

The changes in the scenario input assumptions, such as the change in Irish demand and generation, result in different levels of change in the additional constraint costs for the Cap and Floor Window 3 projects. Many of the projects show an increase in additional constraint costs without the CRF. Higher imports from Ireland lead to increased flows across GB resulting in additional balancing actions. The level of change seen in additional constraint costs is dependent on many factors including the location of the project, how the change to the scenario impacts electricity flows within GB and the resultant flows on that project, and for the MA case, flows on the other Cap and Floor Window 3 projects.

The inclusion of the Constraint Reduction Factor results, not surprisingly, in a reduction in additional constraint costs, but this varies between scenarios. The impact of the CRF also varies significantly between projects.

5. Frequency response

Introduction

This indicator assesses the potential savings that an interconnector or OHA may provide to the grid through the provision of frequency response services which are necessary to ensure system frequency remains at acceptable levels.

Note: The modelling and analysis in this section is the same as that within the March 2024 report. It was not necessary to repeat the work because the change in modelling assumptions would not produce a material change in the results. Although the updates to the scenarios do result in changes to import and export flows, particularly for LirIC and MaresConnect, tests showed that the resultant changes in frequency response savings were within the range of +/-£10m PV. The change is limited as the methodology assumes that only a set percentage of capacity on the interconnector or OHA is available for FR services in any given hour, assuming there is flow across the project. Hence the FR saving is dependent on the volume of flow on the IC/OHA in any given hour to a certain extent, but this is essentially capped. The FR saving is also limited by how many hours in each year the IC/OHA is flowing.

Frequency response is the first of the system operability assessment areas covered in this report. All UK appliances and electrical equipment are designed to work at 50Hz. If the frequency is not 50Hz then appliances and equipment will not work. The tolerance is very small, meaning that the NESO has to keep the frequency within a tight window either side of 50Hz.

Frequency control is achieved through two types of service: response and reserve. Frequency response services are automatically activated using a measurement of frequency to determine an appropriate change in active power. Reserve is dispatched manually by a control room operator following an observed event or in anticipation of a system need. Both response and reserve can deliver a change in active power, provided by a source of either generation or demand. The fundamental aim of our frequency control strategy is to maintain system frequency at the target of 50Hz. While maintaining the frequency, we must also balance the costs and impacts of our actions against the residual level of risk and benefits delivered to the end consumer.

To maintain a stable system frequency of around 50Hz, (set by the Security and Quality of Supply Standard), the NESO procures 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%. 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.

Each future energy scenario assumes a different level of inertia on the network, with each scenario projecting less inertia than is currently on the system. Inertia levels largely impact the volume of response that is required on the network, with lower inertia systems requiring more and faster frequency response. 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 within steady-state limits. Scenarios with more asynchronous and variable sources of generation will likely require more reserve and response.

Currently most asynchronous generation such as renewables, batteries and interconnectors use power electronic convertors which are insensitive to changes in system voltage, frequency and phase: these are known as grid following. 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.

Methodology

This section describes the methodology for assessing the potential effects on frequency response, both in terms of provisions and requirements. It covers the evaluation of the potential for interconnectors and OHAs to provide frequency response, and the potential value.

The following assumptions are made for the methodology:

- An interconnector or OHA may not be able to reserve capacity to provide a frequency response service because the interconnector or OHA does not decide their operating profile. Unless they withhold capacity from the day-ahead market, they will not be able to guarantee firm capacity. An alternative is to assume that the interconnector can participate in frequency response provision because the frequency response service takes place post-gate closure, i.e. within-day. This would enable interconnectors to provide certainty regarding capacity reservation and availability. Hence flows from the redispatch, or constrained runs are used for the analysis. This simulates the post-gate closure, or within-day supply-demand match taking account of network constraints.
- Agreements are in place with neighbouring TSOs to ensure the impact of providing the service for the GB market is acceptable to the neighbouring TSO. An interconnector delivering frequency response services at one end will see an approximately equal and opposite change in power at the other end. This impacts the neighbouring TSO (and other TSOs in the same synchronous area), their control area and potentially their system frequency and use of response and reserve services. No attempt has been made to attempt to quantify any additional costs that may be incurred by the neighbouring TSO.
- All other technical, regulatory and commercial challenges are overcome.
- There is no repositioning of flows across the interconnector, that is the interconnector continues to import or export or remains at float.
- For each interconnector or OHA, the maximum loading level of frequency response is assumed to be 10% of available capacity. In theory the interconnector or OHA may be able to provide a higher level but this may cause issues with the connected foreign system.

To calculate the potential savings associated with interconnectors providing frequency response, we used the constrained redispatch from the NESO's pan-European market model, BID3, to calculate the potential MWh of frequency response available for each of the interconnectors in turn, for each modelled year, for each of the three scenarios for both the FA and MA cases.

Frequency response requirements were calculated using NESO's in-house tool, which can calculate the total requirement for frequency response based on a range of inputs, including system demand and the largest loss on the system.

To calculate the potential savings, we have used publicly available frequency response costs. Total monthly response costs are published in the Monthly Balancing Services Summary (MBSS) reports[12]. Costs for the new frequency response services of Dynamic Containment (DC), Dynamic Modulation (DM) and Dynamic Regulation (DR) are also available via the NESO Data Portal[13]. We have used data from the MBSS and DC/DM/DR data from the Data Portal to calculate the potential benefit of interconnectors providing frequency response. By assuming that interconnectors provide a frequency response service at a cost equivalent to current DC, DM and DR services, the saving from interconnectors providing the service is equivalent to the difference in average costs observed for frequency response and the average cost observed for DC, DM and DR services.

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[12] https://www.nationalgrideso.com/data-portal/mbss

[13] https://www.nationalgrideso.com/data-portal

Limitations of analysis

There are many challenges in quantifying the potential benefits of interconnectors providing frequency response services. The frequency response requirements landscape will change considerably over the next quarter of a century. There will be many revisions and developments as the energy system continues to go through a period of unprecedented change.

The analysis assumes that all technical, regulatory and commercial challenges are overcome, such as the frequency response service taking place post-gate closure, agreeing frequency exchange rules with the connected foreign system and ensuring effective energy transfer settlement. Rather than provide a range of outcomes for each combination of FA/MA and FES, a single result is produced for each project for each scenario and case.

If all the challenges and issues listed above are not overcome, then the level of service that an interconnector or OHA may be able to provide will be lower than that forecast. However, reform of the NESO's ancillary service and balancing markets is crucial to ensuring that we can operate a zero-carbon electricity system by 2025, and fully decarbonise by 2035. These reforms are designed to make markets more efficient, accessible, and liquid, which may potentially lead to even greater levels of participation from interconnectors and OHAs than assumed within this analysis.

Results

The following figures show the savings for frequency response in present value (25-year, 2022 £m) for each of the Cap and Floor Window 3 projects and OHA pilot projects.

Figure 27: Frequency Response savings for all interconnectors and OHAs for First Additional case, Present Value 25-year, real 2022, £m.

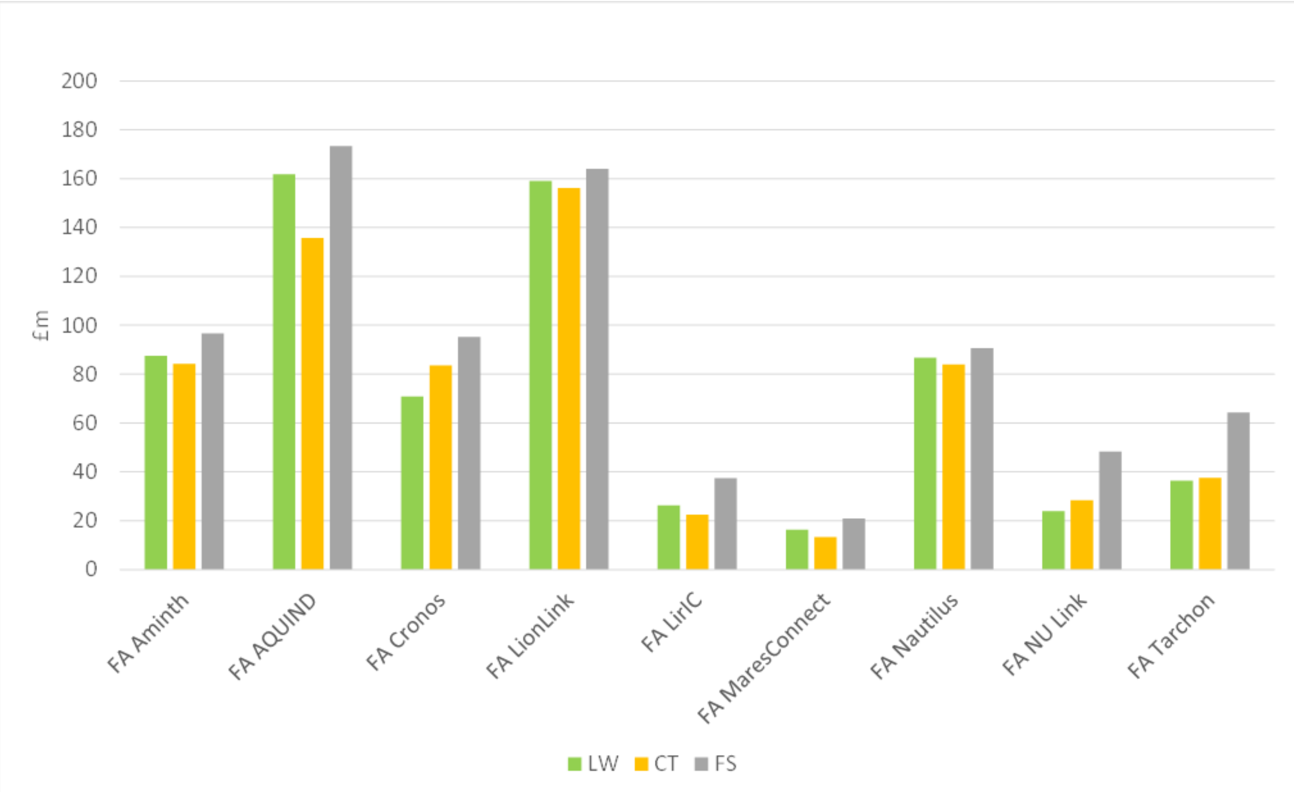
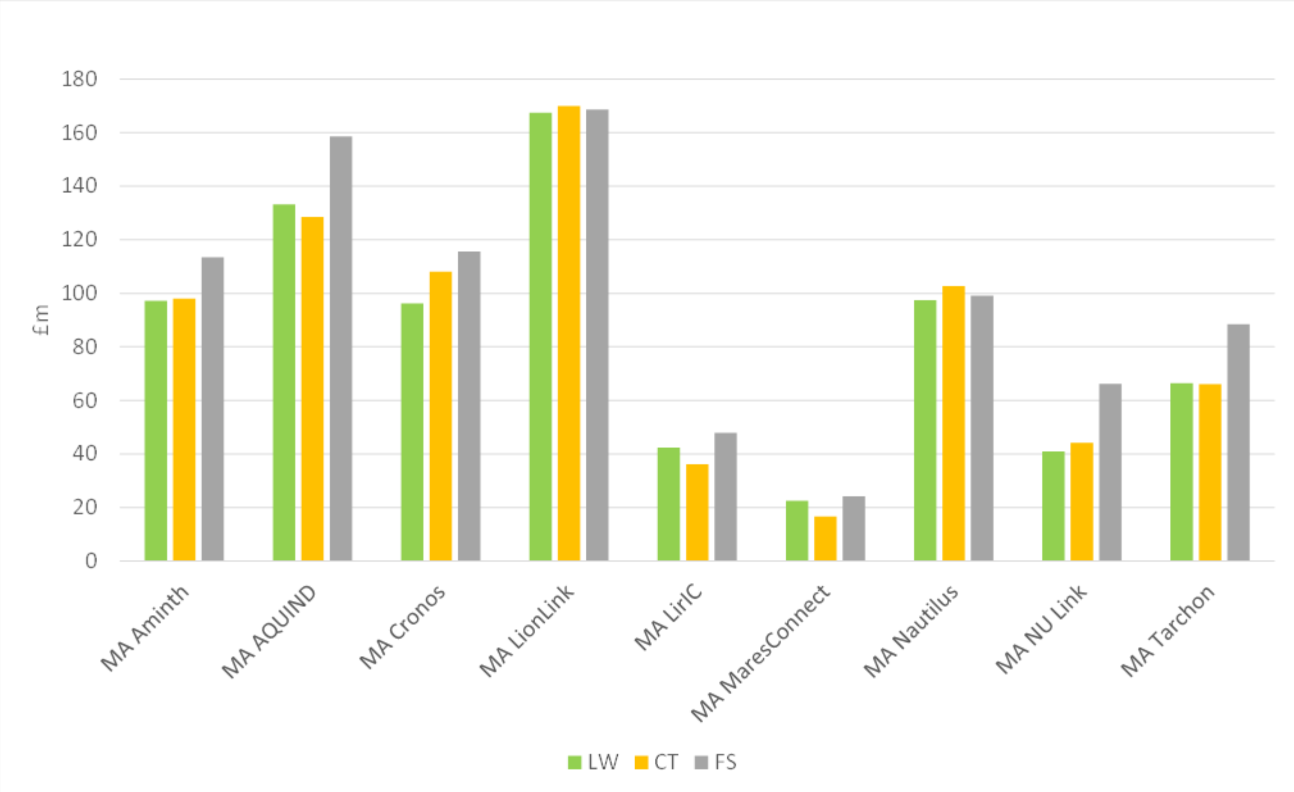


Figure 28: Frequency Response savings for all interconnectors and OHAs for Marginal Additional case, Present Value 25-year, real 2022, £m.



The above figures show the high variation in frequency response savings across projects. This is primarily driven by flow patterns across each project and the resultant availability of capacity for frequency response services.

It is important to note that there is considerable uncertainty around these forecasts. The analysis assumes that the interconnector's potential frequency response provision is provided at costs similar to those experienced in the DC, DR and DM products: this may be overly optimistic if costs do not reach those seen for DC, DR and DM. The interconnector may also decide to not provide frequency response services. Alternatively, it may be possible for interconnectors and OHAs to provide more than 10% of their capacity for frequency response, potentially leading to higher savings.

6. Reactive power support

Introduction

This indicator assesses the potential savings that an interconnector or OHA may provide to the grid through the provision of reactive power services which are necessary to maintain voltage on the transmission system.

Note: The modelling and analysis in this section is the same as that within the March 2024 report. It was not necessary to repeat the work because the change in modelling assumptions would not produce a material change in the results. The level of reactive power benefit provided by each project is calculated from power system analysis. The analysis undertaken for the original March 2024 report highlighted that for the majority of the W3 projects the maximum reactive power support is kept constant for all three cases – float, full-import and full-export. Hence changes in flows will not materially affect the results.

Reactive power is the second of the system operability assessment areas covered in this report. 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 the NESO 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. This section summarises the reactive power impact analysis considering the seven third window interconnectors and two OHA pilot projects.

Methodology

Our analysis considered interconnectors and OHAs to be connected between 2027 to 2031. To analyse the system operability impact with respect to reactive power response, we have analysed a scenario with system minimum demand (hence summer minimum case) corresponding to high system voltage conditions.

This modelling was undertaken using a detailed power system model of the GB electricity network that uses power system analysis software. This enables load flow analysis including active and reactive power modelling. It is separate to the BID3 model used for constraint costs analysis.

To develop the network model for this analysis, the starting point was the 2030 network. The impact of additional interconnectors or OHAs is analysed by including them within this network model. All projects connecting before or after 2030 are analysed within the single 2030 model because the connection dates are all close to 2030. The key assumptions are:

- The Future Energy Scenarios (FES) 2022 Leading the Way scenario is used. Due to time constraints, it was not possible to create the necessary network model to be able to use either Consumer Transformation or Falling Short.
- Minimum System demand of 16,110 MW and 13,725 MVAr for England and Wales for a 2030 network.
- 90% availability scaling factors applied for fixed reactors, SVCs and STATCOMs.
- All future reactors which are either in tender stage or under-construction have been assumed in the background.
- Voltage control circuits are also used to resolve voltage profiling.

For each spot year model, multiple scenarios have been simulated to capture the interconnectors and OHA pilot project maximum benefit. We have considered the extremes, Full Import (the interconnector or OHA is at maximum import at all times), Full Export (the interconnector or OHA is at maximum export at all times) and Float (i.e. the interconnector or OHA does not import or export at any time, i.e. 0MW) conditions as summarised below for each interconnector and OHA[14].

Table 6: Import/export scenarios considered for each interconnector and OHA.

Project Name	Asset Type	Connecting country	GB Substation	Scenarios	Import (MW)	Export (MW)
Aminth	W3	Denmark	Mablethorpe 400kV	Base + Aminth	1400	-1400
AQUIND	W3	France	Lovedean 400kV	Base + AQUIND	2000	-2000
Cronos	W3	Belgium	Kemsley 400kV	Base + Cronos	1400	-1400
LirIC	W3	Northern Ireland	Hunterston 400kV	Base + LirIC	700	-700
MaresConnect	W3	Ireland	Bodelwyddan 400kV	Base + MaresConnect	750	-750
NU-Link	W3	Netherlands	Mablethorpe 400kV	Base + NU-Link	1200	-1200
Tarchon	W3	Germany	East Anglia Connection Node 400kV	Base + Tarchon	1400	1400
Lionlink	OHA	Netherlands	Friston 400kV	Base + Lionlink	1800	-1800
Nautilus	OHA	Belgium	Grain 400kV	Base + Nautilus	1400	-1400

Reactive power support capabilities of the proposed interconnector or OHA are analysed by carrying out pre-fault voltage studies for the network without the proposed W3 interconnector or OHA and then the network with the proposed W3 interconnector or OHA.

- The network is studied with all existing and under-construction/tendered reactive power support devices.

- For full-import and full-export cases, the system is re-balanced with generators which are further away from the local area. We have endeavoured to ensure power flow direction on all interconnectors and OHAs is the same for all countries i.e. all are in importing or exporting.

Each interconnector or OHA is studied independently by keeping other interconnectors disconnected. But, in real time operation, the reactive power will be shared by nearby active interconnectors.

Due to non-availability of actual reactive capability of proposed Voltage Source Converter (VSC) interconnectors, we have assumed a conservative figure of reactive capacity @0.95 power factor based on past

[14]The power system modelling was not repeated for the updated analysis. We do not believe this would have a material impact on the results.

project data. Also, as the reactive capacity of VSC based HVDC is independent of active power flow, the maximum reactive power support is kept constant for all three cases (float, full-import and full-export).

As reactive power is a local problem in its nature, the voltage studies focus on the local areas where the interconnectors are to be connected. All substations within a two-substation range of the connection points to be considered are studied.

Limitations of analysis

Reactive Power generation and absorption requirements for voltage control are regional and vary significantly across the electricity system. System requirements are driven by many factors including demand, generation, and system conditions. Interconnectors are located on the periphery of the network and may not be in the optimal location for providing reactive power services. In addition, long term forecasts for reductions in reactive power costs may be over-optimistic, as recent geopolitical events have caused increased volatility in reactive power costs.

Results

Below is a summary of the indicating reactive power benefit for interconnectors and OHAs across the scenarios analysed. The results show an estimate of reactive support benefits assuming Voltage Source Converter (VSC) based technology. It is important to note however, that there is ongoing work to understand the future voltage requirements across Great Britain and if any reactive power support is procured as a result, the indicated benefits from interconnectors or OHAs might be reduced.

Table 7: Reactive power benefit for each interconnector and OHA.

Project Name	Asset Type	Capacity	GB Connected Node	MVAr_Float	MVAr_Import	MVAr_Export
Aminth	W3	1400	Mablethorpe 400kV	-460	-460	-460
AQUIND	W3	2000	Lovedean 400kV	-660	-540	-360
Cronos	W3	1400	Kemsley 400kV	-460	-460	-460
LirIC	W3	700	Hunterston 400kV	-230	-230	-230
MaresConnect	W3	750	Bodelwyddan 400kV	-250	-250	-250
NU-Link	W3	1200	Mablethorpe 400kV	-400	-400	-400
Tarchon	W3	1400	East Anglia Connection Node 400kV	-460	-460	-450
Lionlink	OHA	1800	Friston 400kV	-590	-590	-590
Nautilus	OHA	1400	Grain 400kV	-460	-460	-460

To calculate the potential savings associated with interconnectors and OHAs providing reactive power, we used the constrained redispatch flows from the NESO's pan-European market model BID3 to calculate the potential MVAr available for each of the interconnectors in turn, for each modelled year, for each of the three scenarios[15] for both the First Additional and Marginal Additional cases. Historic reactive power volumes and expenditures are available via the NESO's Monthly Balancing Services Summary reports[16] which provide a historic cost per MVArh. As the reactive power market evolves over the coming decades, we have assumed a percentage reduction in voltage costs[17] which is applied to the theoretical MVAr provided by each interconnector and OHA.

[15] The reactive power benefits from **Error! Reference source not found.** were applied to Leading the Way, Consumer Transformation a nd Falling Short.

[16] https://www.nationalgrideso.com/data-portal/mbss

[17]Based on economic modelling undertaken for the NESO.

The following figures represent the potential savings if all the potential reactive power benefit that could be provided by each interconnector is actually required: this may not be the case. Hence the values for potential reactive power savings represent an upper estimate.

Figure 29: Reactive power savings for all interconnectors and OHAs for First Additional case, Present Value 25-year, real 2022, £m.

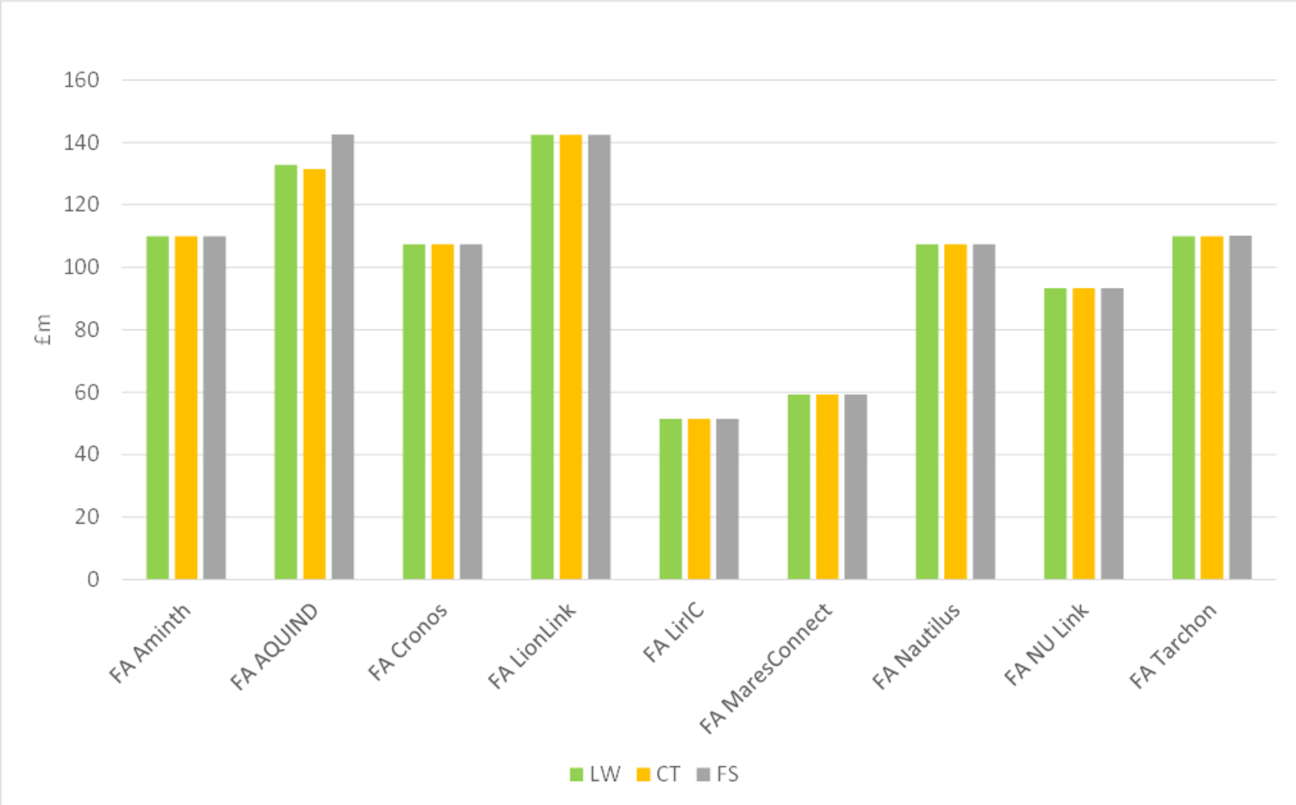
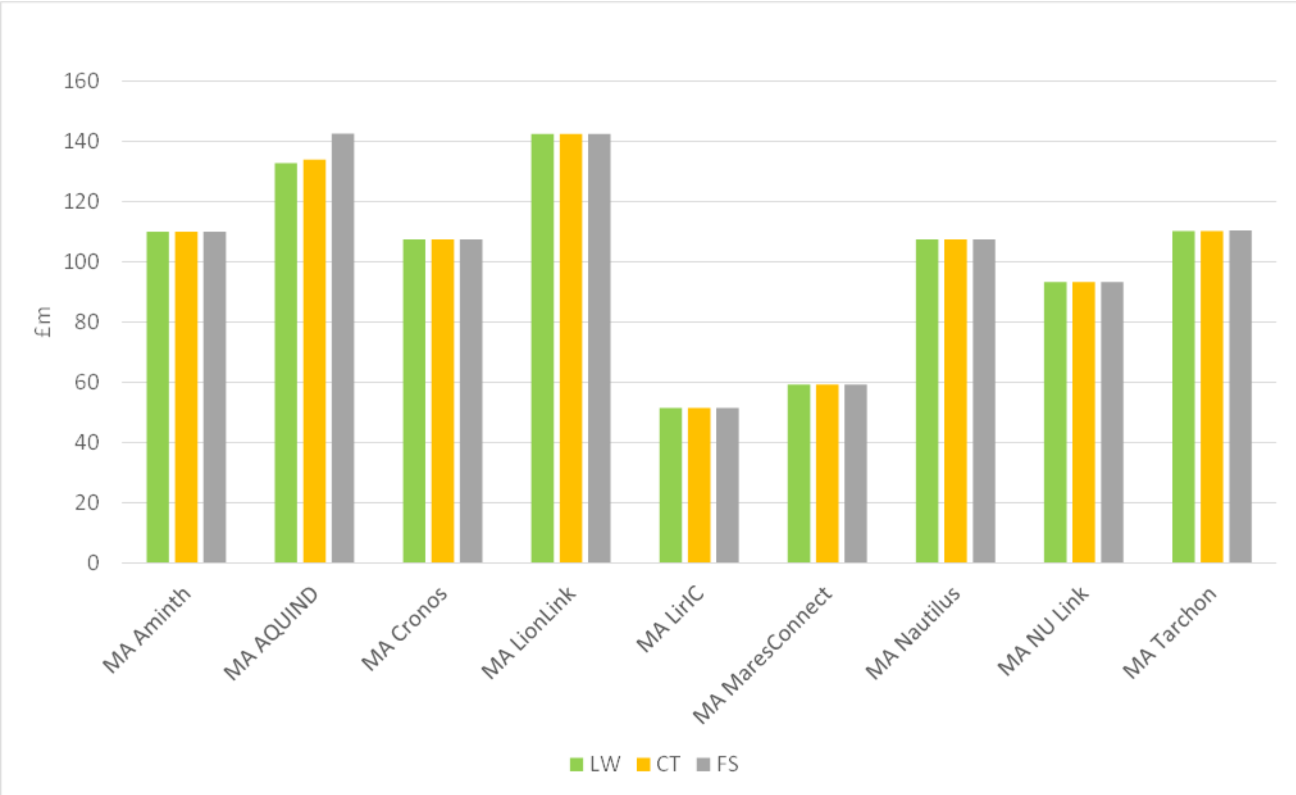


Figure 30: Reactive power savings for all interconnectors and OHAs for Marginal Additional case, Present Value 25-year, real 2022, £m.



The above figures show the potential reactive power savings for both the First Additional and Marginal Additional cases. The figures show that there is little or no variation between the FA and MA cases, and between scenarios. This is because Error! Reference source not found. shows there is little variation in reactive power benefit from e ach interconnector whether it is importing, exporting or at float.

7. Restoration

Introduction

This indicator assesses the potential savings that an interconnector or OHA may provide to the grid through the provision of restoration services which are necessary to ensure the NESO can restore the system in the event of a partial or total shutdown.

Note: The modelling and analysis in this section is the same as that within the March 2024 report. It was not necessary to repeat the work because the change in modelling assumptions would produce no change in the results. The restoration analysis is not flow dependent and as the changes to the scenarios have no impact on GB generation assets, there will be no changes to the restoration savings.

Restoration (formerly known as Black Start) is the third of the system operability assessment areas covered in this report. 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 synchronization 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.

The Electricity System Restoration Standard (ESRS) prescribes new restoration targets effective 31st December 2026, for the NESO to have sufficient capability in place, in an event of a total system shutdown, to restore:

- 60% of transmission electricity demand being restored within 24 hours in all regions, and
- 100% of electricity demand being restored within 5 days nationally.

To be ESRS-compliant by December 2026, the NESO is adopting a restoration approach that implements both traditional and non-traditional restoration service providers. The NESO is proposing a holistic restoration approach that considers both top-down and bottom-up approach to restoration. This approach removes barriers to entry for markets and allows distributed energy resources (DERs) to participate in restoration.

Our vision is that by the middle of the decade we will be running a fully competitive restoration procurement process wherever advantageous, with submissions from a wide range of technologies connected at different voltage levels on the network, with Transmission Owners (TO) and Distribution Network Operators (DNO).

The NESO's principles for procuring restoration services are:

• A clear and transparent requirement.

• Enabling competition, where appropriate.

• Reducing and removing barriers to entry to enable broader participation.

Methodology

The current contracting strategy for restoration services is to have seven zones, with an average of 3 plants per zone. For this strategy generation must meet demand in local areas whilst maintaining voltage and frequency requirement: this is where the inherent capability of VSC interconnectors provide a great opportunity. For this analysis no limit is placed on the number of interconnectors that can be contracted within each zone.

The analysis assumes the following:

- Zero additional capital costs for restoration services from VSC interconnectors or OHAs.

- Zonal contracting strategy remains in place over the life of the interconnector or OHA.
- Capital costs remain the same for new technologies.

The current plant providing restoration services in each zone were cross-referenced against the three FES22 scenarios to determine which plant would still be available to provide Black Start services across the forecast period.

Existing contractor costs have been used to calculate future contracting cost components, covering availability, testing, feasibility and capital for a range of service providers, including existing providers including interconnectors and new entrants. The average cost of existing, interconnector and new entrants providing a restoration service has been calculated.

Potential savings can then be calculated, with higher savings where there are forecast to be more new market participants in a particular zone driving increased competition.

Limitations of analysis

There will be fundamental changes to the restoration services landscape in the coming decades as the system transforms and becomes more reliant on intermittent energy sources. There is a long-term objective of diversifying technologies and reducing restoration costs. New entrants will participate in restoration services, both at the transmission and distribution network level. Forecasting future cost assumptions over such a long-time horizon is difficult, especially with emerging technologies. The levels of participation of interconnectors and OHAs in providing restoration services may be higher or lower than those assumed leading to relatively higher or lower savings.

Results

Figure 31: Potential savings for restoration services provided by each interconnector for First Additional case for each of the scenarios, PV, 25-years, real 2022, £m.

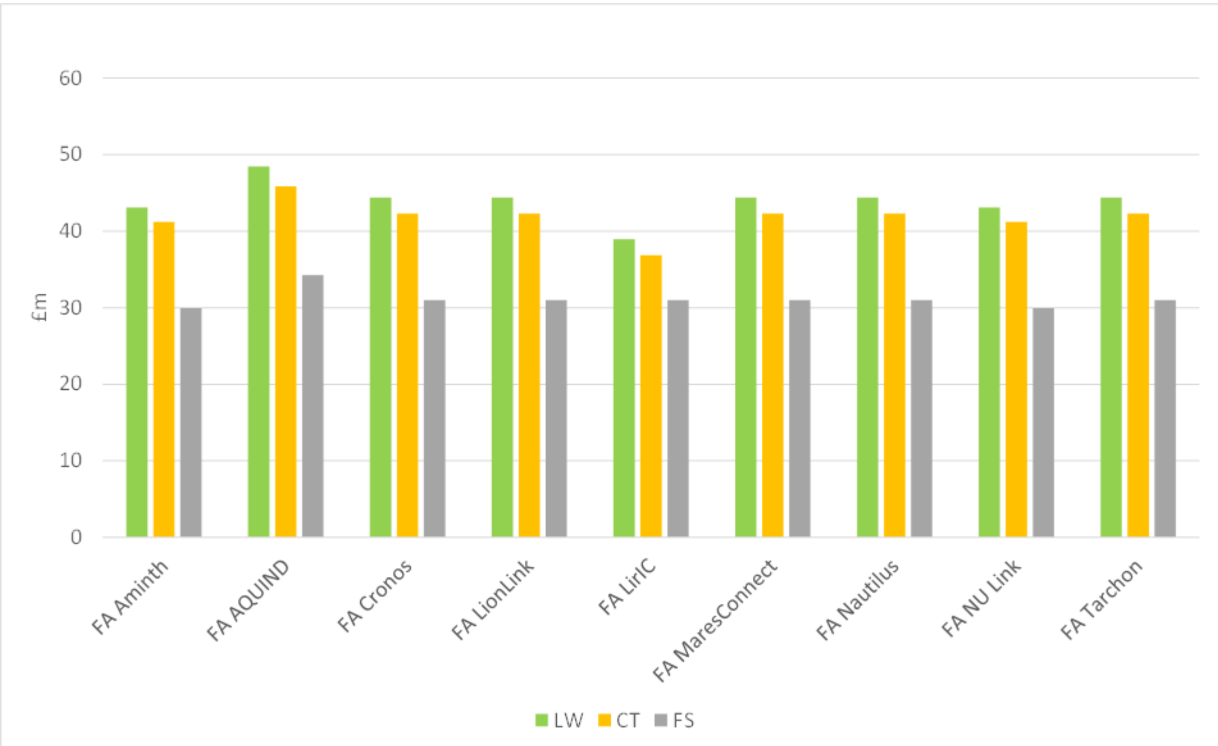
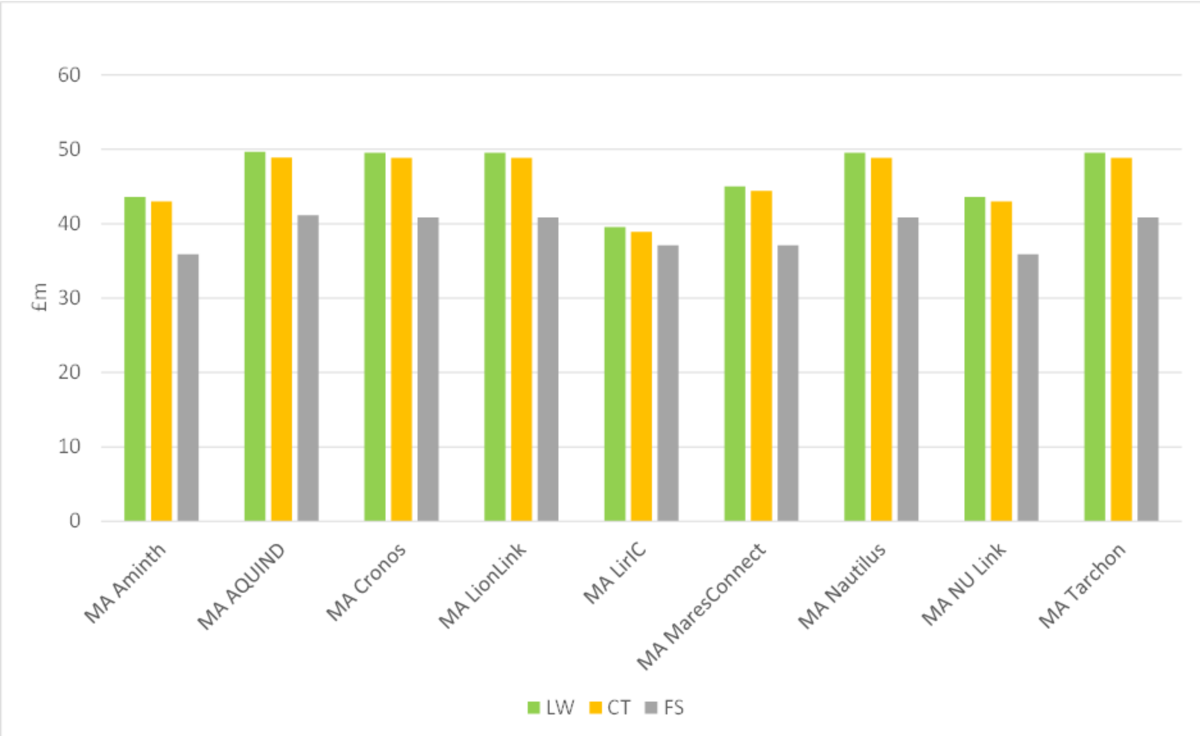


Figure 32: Potential savings for restoration services provided by each interconnector for Marginal Additional case for each of the scenarios, PV, 25-years, real 2022, £m.



The variations in restoration services are primarily driven by a combination of the geographic location of the interconnector or OHA, and the other relevant restoration providers in that zone, and the FES scenario, which forecasts the likely development of generation assets within that zone. Restoration savings are higher in the Marginal Additional case, as lower interconnector base costs were assumed driven by increased competition.

As stated previously, there is considerable uncertainty regarding forecasting savings in restoration services, as over the next decade and beyond, the GB generation technology mix, and the make-up of participants in the restoration market will change fundamentally. New market participants may drive competition further such that interconnector and OHA costs are even lower, providing even greater savings, or alternatively new entrants market activity may result in reduced participation from interconnectors or OHAs.

8. Avoided RES curtailment

Introduction

This indicator assesses the potential volumes of renewable energy supply (RES) curtailment that can be avoided when an interconnector or OHA is connected to the grid.

Note: The modelling and analysis in this section is new. It was necessary to repeat the modelling because the change in modelling assumptions produces a material change in the results.

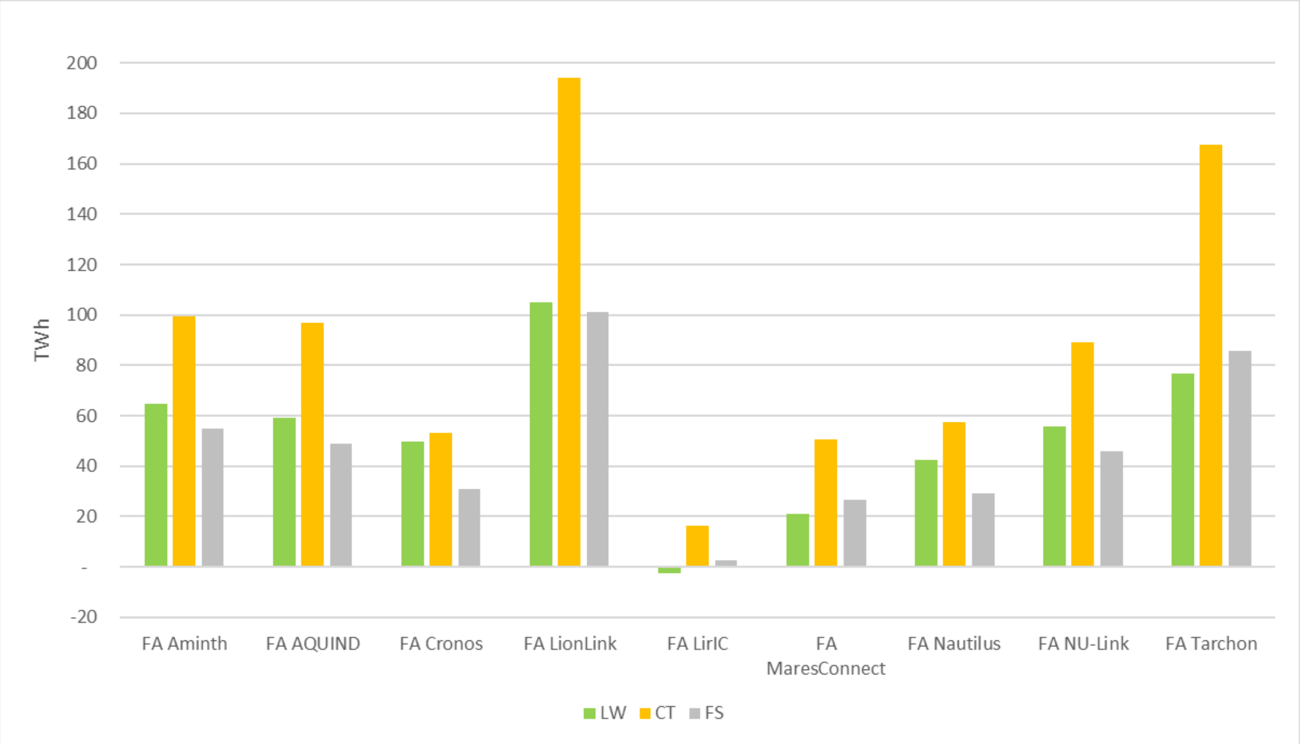
Curtailment is when the output from a generation unit connected to the electricity system is reduced due to operational balancing. To avoid curtailment, flexible solutions such as interconnectors, energy storage, Demand Side Response (DSR) or electrolysis could be used to maximise the use of renewable energy supplies (RES).

Methodology

RES curtailment is a standard output from our pan-European market model BID3. For this analysis we have used outputs from the constrained, redispatch to provide a forecast of the levels of RES curtailment that can be avoided when each of the Window 3 interconnector and OHA pilot projects are included.

Results

Figure 33: RES curtailment avoided in the First Additional case. 25-year total.

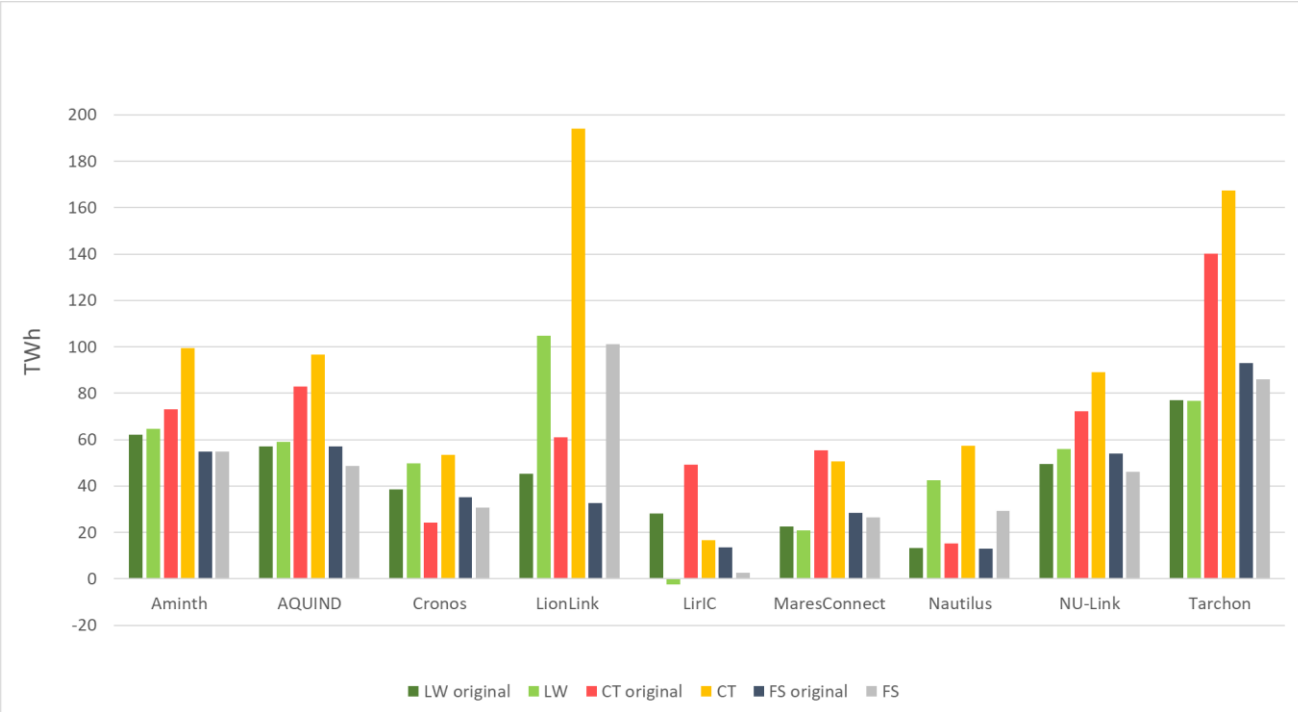


The above figure shows RES curtailment avoided for each W3 interconnector and OHA pilot project for each scenario for the 25-year life of the project, for the First Additional case. The figure shows that all the projects provide reductions in RES curtailment for all scenarios in the First Additional case. The highest levels of RES curtailment avoided are seen in the Consumer Transformation scenario, but there are significant volumes of RES curtailment avoided in both Leading the Way and Falling Short. Consumer Transformation has high levels of renewable generation combined with low hydrogen production from electrolysis which leads to the highest levels of RES curtailment across the three scenarios. Hence the addition of an extra interconnector or OHA in Consumer Transformation provides an opportunity for increased levels of avoided RES curtailment. Leading the Way also has high levels of renewable generation but has higher levels of hydrogen production from electrolysis than in Consumer Transformation hence the lower levels of RES curtailment avoided compared to Consumer Transformation. Falling Short has relatively lower levels of renewable generation but also has minimal levels of electrolysis leading to high levels of RES curtailment, hence high levels of RES curtailment avoided when an additional interconnector or OHA is added.

LionLink results in the highest levels of RES curtailment avoided in the First Additional case. An examination of the annual RES curtailment figures for LionLink shows that the final three years modelled in BID3 (2040 to 2042), which are used to extrapolate the later years, are particularly high.

The following figure compares the results for RES curtailment avoided for the original analysis and for Nautilus at Grain with 1.4GW link and Irish demand and generation from TYNDP 2022.

Figure 34: RES Curtailment avoided for First Additional, for the original analysis and for Nautilus at Grain with 1.4GW link and Irish demand and generation from TYNDP 2022.

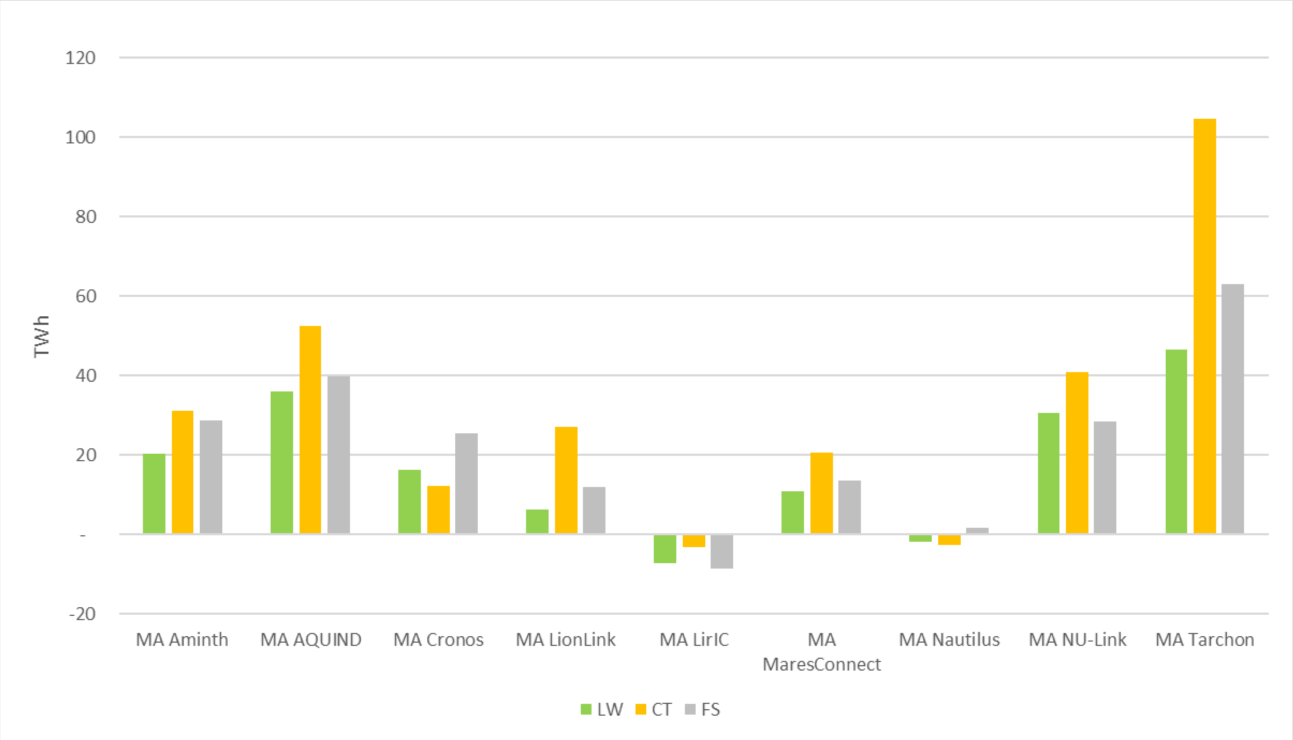


The figure shows increased levels of RES curtailment avoided for most projects for Leading the Way and Consumer Transformation, most notably for LionLink. The increased levels of Irish imports lead to increased exports on some of the W3 projects leading to increased RES curtailment avoided.

LirIC and MaresConnect show a reduction in RS curtailment avoided, as the inclusion of each of the projects results in higher imports to GB.

LionLink shows a significant increase in RES curtailment avoided in CT as the project has a 50% increase in exports in the latest modelling. Import and export flows across the W3 interconnectors and OHAs are shown in the individual project chapters.

Figure 35: RES curtailment avoided in the Marginal Additional case. 25-year total.

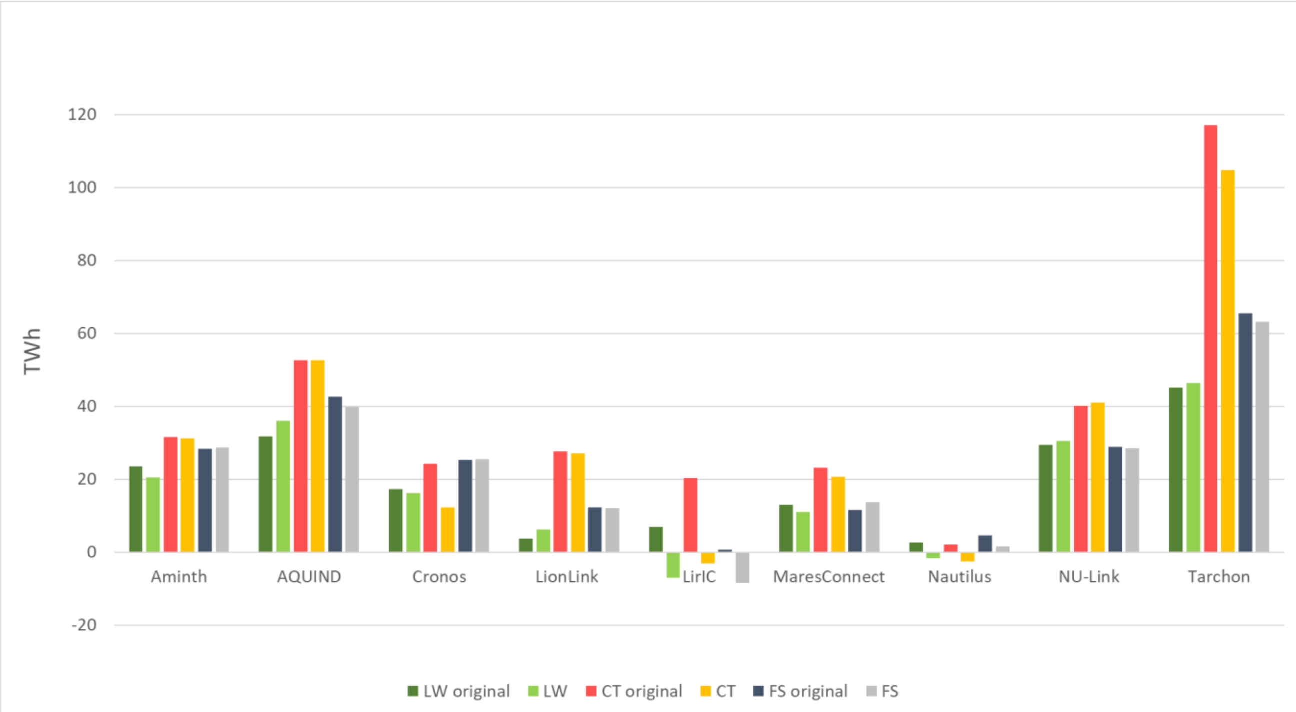


The above figure shows RES curtailment avoided for each W3 interconnector and OHA pilot project for each scenario for the 25-year life of the project, for the Marginal Additional case. The figure shows that all the projects provide reductions in RES curtailment for all scenarios in the Marginal Additional case, except for LirIC and Nautilus. LirIC increases RES curtailment in all three scenarios and Nautilus increases RES curtailment in LW and CT, albeit at low levels. In general, for the other projects the scale of the RES curtailment avoided are lower than in the First Additional case.

The highest levels of RES curtailment avoided are seen in the Consumer Transformation scenario, but for most of the projects there are significant volumes of RES curtailment avoided in both Leading the Way and Falling Short.

Tarchon results in the highest levels of RES curtailment avoided in the Marginal Additional case. An examination of the annual RES curtailment figures for Tarchon shows that the final three years modelled in BID3 (2040 to 2042), which are used to extrapolate the later years, are particularly high.

Figure 36: RES Curtailment avoided for Marginal Additional, for the original analysis and for Nautilus at Grain with 1.4GW link and Irish demand and generation from TYNDP 2022.



The above figure shows that in the Marginal Additional case there is less change in the levels of RES curtailment avoided in the latest analysis when compared to that for the March 2024 work. This is to be expected, because the inclusion of all the nine Cap and Floor Window 3 projects reduces the impact of the changes in the Nautilus line capacity and the change in Irish demand and generation. The exceptions are for LirIC, MaresConnect and Nautilus. LirIC and MaresConnect result in major increases in import flows to GB, leading to reductions in RES curtailment avoided, and in some cases, increases in RES curtailment.

9. Results by project

Introduction

The following chapters shows the results for each individual W3 interconnector and OHA.

The results include:

- PV constraint costs
- Annual constraint costs (undiscounted)
- Annual constraint costs (discounted), without and with Constraint Reduction Factor
- Annual import and export flows for dispatch and redispatch
- Change in constraint costs by boundary
- PV system operation
- RES curtailment avoided

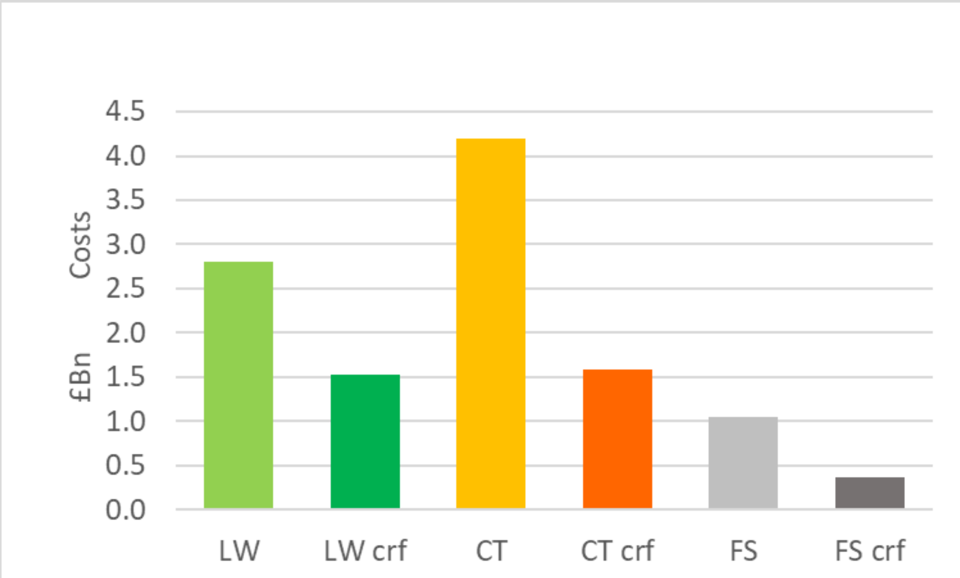
Note that the **change in constraint costs by boundary** is shown without the Constraint Reduction Factor. This is because the CRF is applied to the aggregated additional constraint cost figures. The CRF assumes additional reinforcements over and above those already included within NESO's long term network planning and hence it is not possible to accurately forecast the additional constraint costs by boundary when the CRF is applied.

10. Aminth

Although Aminth is physically an OHA, it applied via Window 3, and hence for the purposes of this assessment it is classified as a W3 project. It has a capacity of 1.4GW and connects to Denmark.

PV constraint costs

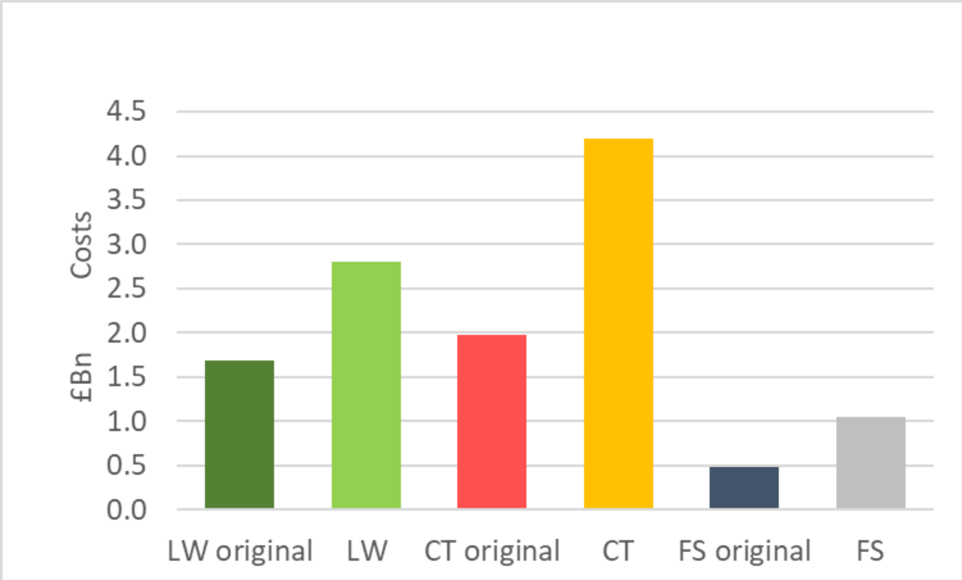
Figure 37: PV additional constraint costs due to Aminth for the First Additional case, Present Value 25-year, real 2022, £m, without and with Constraint Reduction Factor applied.



The above figure shows the additional constraint costs with the inclusion of Aminth for the FA case. Without the Constraint Reduction Factor applied, in the Leading the Way scenario (LW) constraint costs are increased by £2.8bn, in Consumer Transformation (CT) by £4.2bn and in the Falling Short (FS) scenario by £1.0bn.

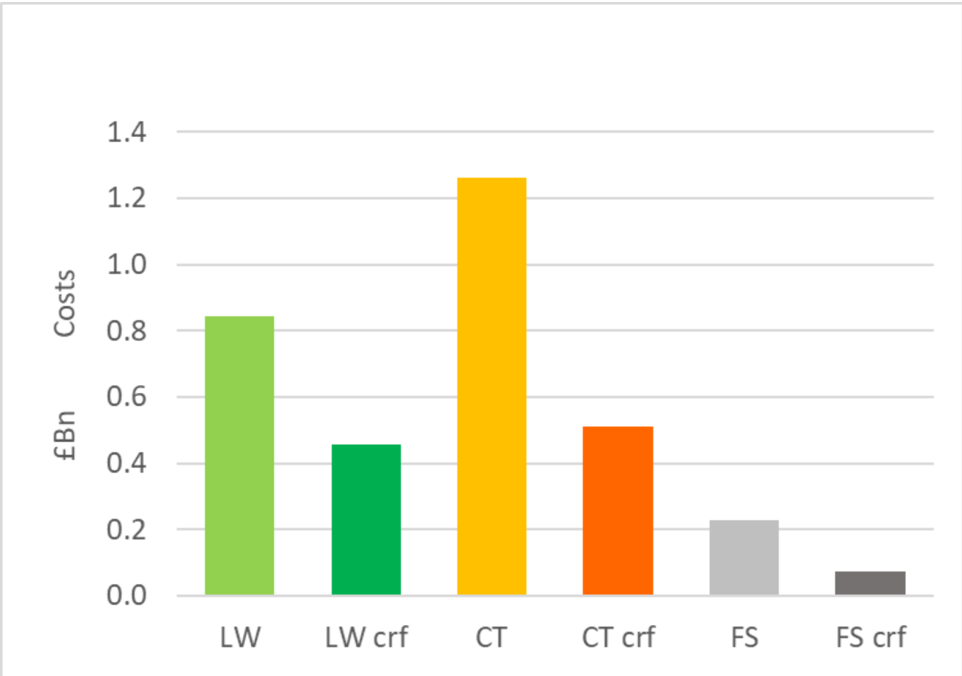
With the Constraint Reduction Factor applied, in the Leading the Way scenario (LW) constraint costs are increased by £1.5bn, in Consumer Transformation (CT) by £1.6bn and in the Falling Short (FS) scenario by £0.4bn.

Figure 38: PV additional constraint costs due to Aminth for the First Additional case, Present Value 25-year, real 2022, £m, for the original analysis (March 2024) and for Nautilus at Grain with 1.4GW link and Irish demand and generation from TYNDP.



The above figure shows that the changes made to the scenarios, that is the reduction in the capacity of the link connecting the Nautilus offshore platform to Belgium from 3.5GW to 1.4GW and the change in Irish demand and generation to reflect final TYNDP data results in a significant increase in constraint costs in all three scenarios.

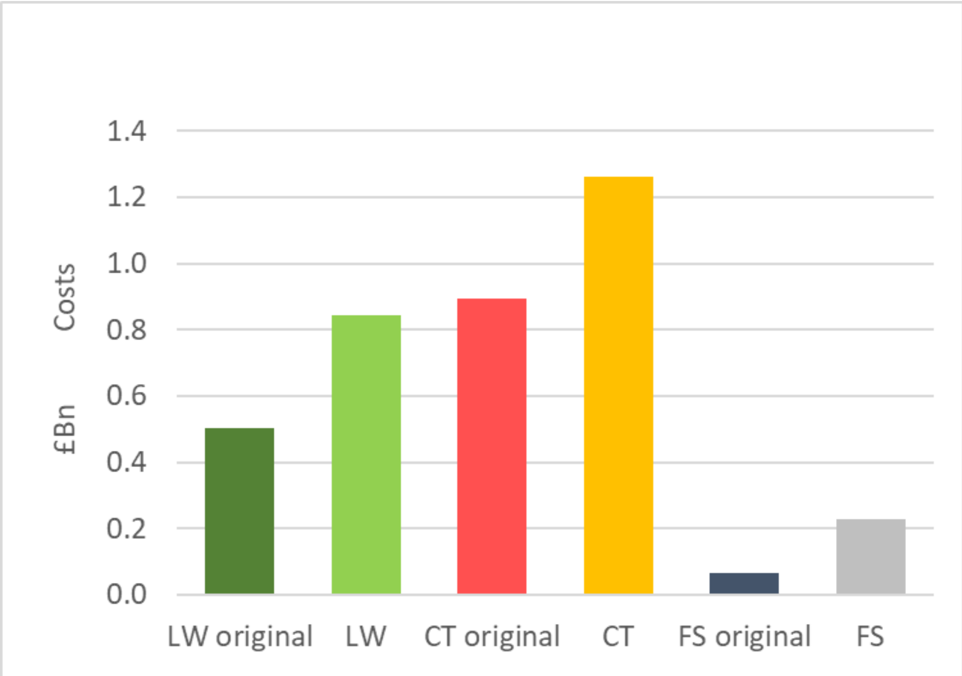
Figure 39: PV additional constraint costs due to Aminth for the Marginal Additional case, Present Value 25-year, real 2022, £m, without and with Constraint Reduction Factor applied.



The above figure shows the additional constraint costs with the inclusion of Aminth for the MA case. Without the Constraint Reduction Factor applied, in the Leading the Way scenario (LW) constraint costs are increased by £0.8bn, in Consumer Transformation (CT) by £1.3bn and in the Falling Short (FS) scenario by £0.2bn.

With the Constraint Reduction Factor applied, in the Leading the Way scenario (LW) constraint costs are increased by approximately £0.5bn, in Consumer Transformation (CT) by £0.5bn and in the Falling Short (FS) scenario by £0.1bn.

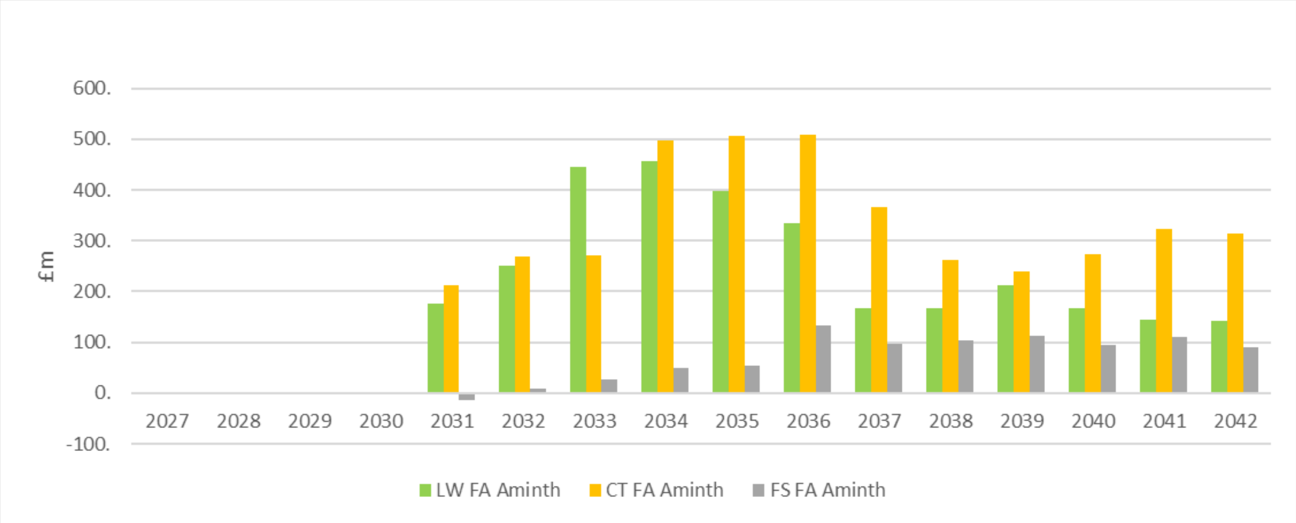
Figure 40: PV additional constraint costs due to Aminth for the Marginal Additional case, Present Value 25-year, real 2022, £m, for the original analysis (March 2024) and for Nautilus at Grain with 1.4GW link and Irish demand and generation from TYNDP.



The above figure shows that the changes made to the scenarios, that is the reduction in the capacity of the link connecting the Nautilus offshore platform to Belgium from 3.5GW to 1.4GW and the change in Irish demand and generation to reflect final TYNDP data results in a significant increase in constraint costs in all three scenarios.

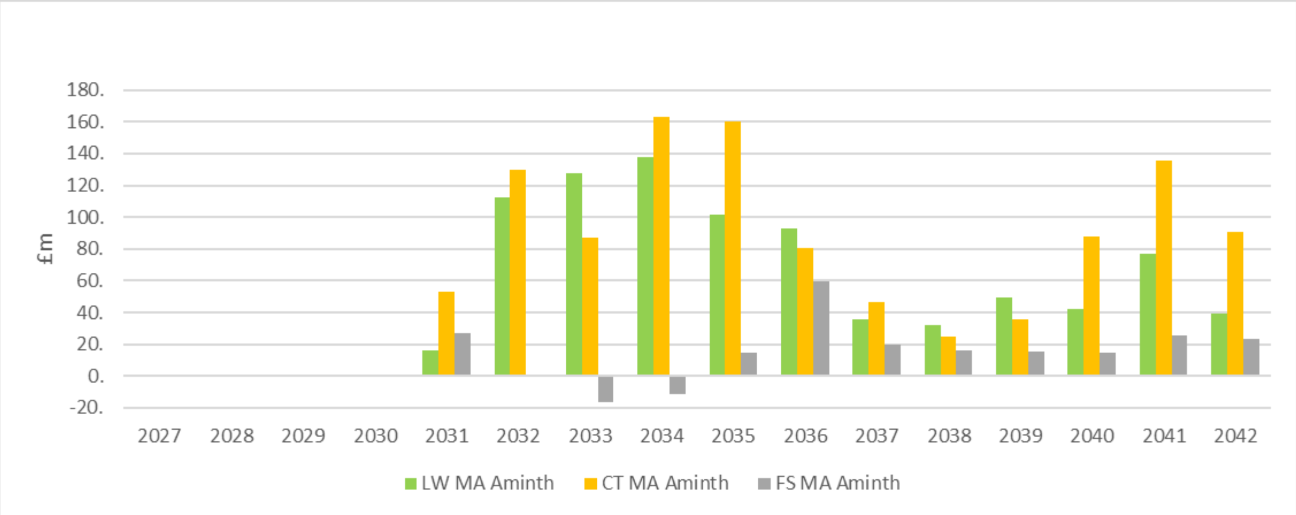
Annual constraint costs (undiscounted)

Figure 41: Additional annual constraint costs (undiscounted) due to Aminth for the First Additional case.



The above figure shows that Aminth results in an increase in constraint costs of approximately £300m to £500m (undiscounted) in CT and LW for the years 2034 to 2036. In FS constraint cost increases are much lower, with small savings in 2031. The results are significantly higher than the original (March 2024) results.

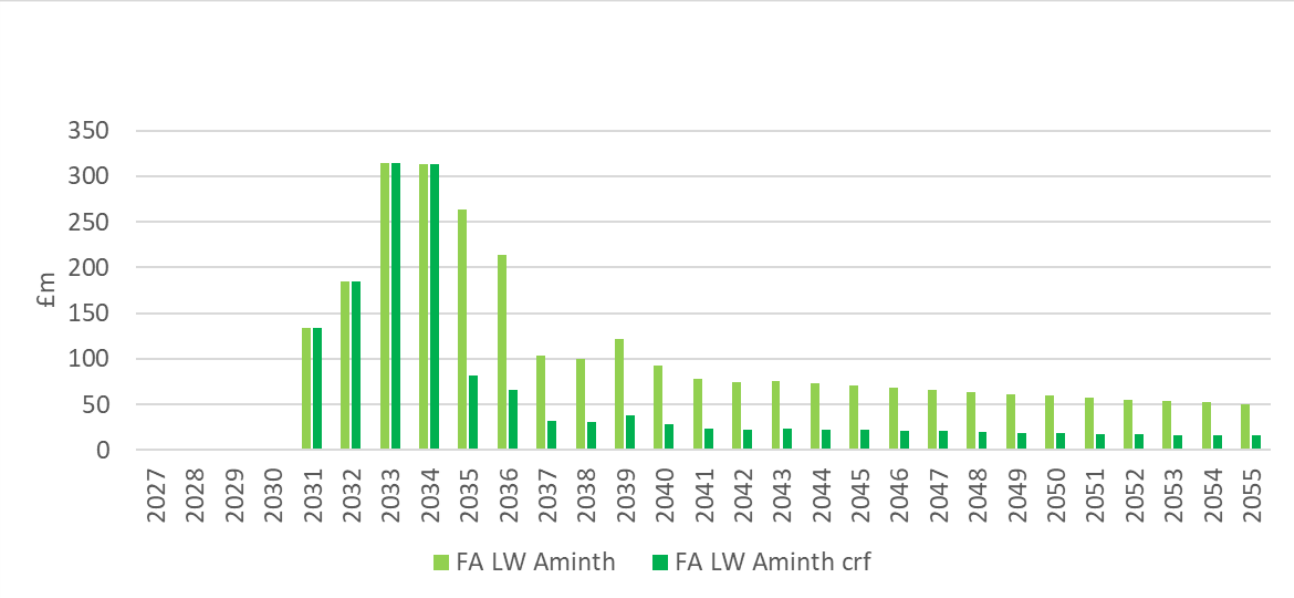
Figure 42: Additional annual constraint costs (undiscounted) due to Aminth for the Marginal Additional case.



In the Marginal Additional case, Aminth results in an increase in constraint costs of approximately £100m to £150m (undiscounted) in CT and LW for the years 2032 to 2035. FS shows constraint savings for the years 2033 to 2034, and for the other years shows lower levels of additional constraint costs compared to LW and CT. The results are significantly higher than the original (March 2024) results.

Annual constraint costs (discounted), without and with Constraint Reduction Factor

Figure 43: Additional annual constraint costs (discounted) due to Aminth for the First Additional case for Leading the Way, without and with Constraint Reduction Factor applied.



The above chart shows the additional constraint costs without and with the Constraint Reduction Factor (CRF) applied for the Leading the Way scenario for the First Additional case. The chart shows the impact of the CRF being applied from 2035 onwards.

Figure 44: Additional annual constraint costs (discounted) due to Aminth for the First Additional case for Consumer Transformation, without and with Constraint Reduction Factor applied.

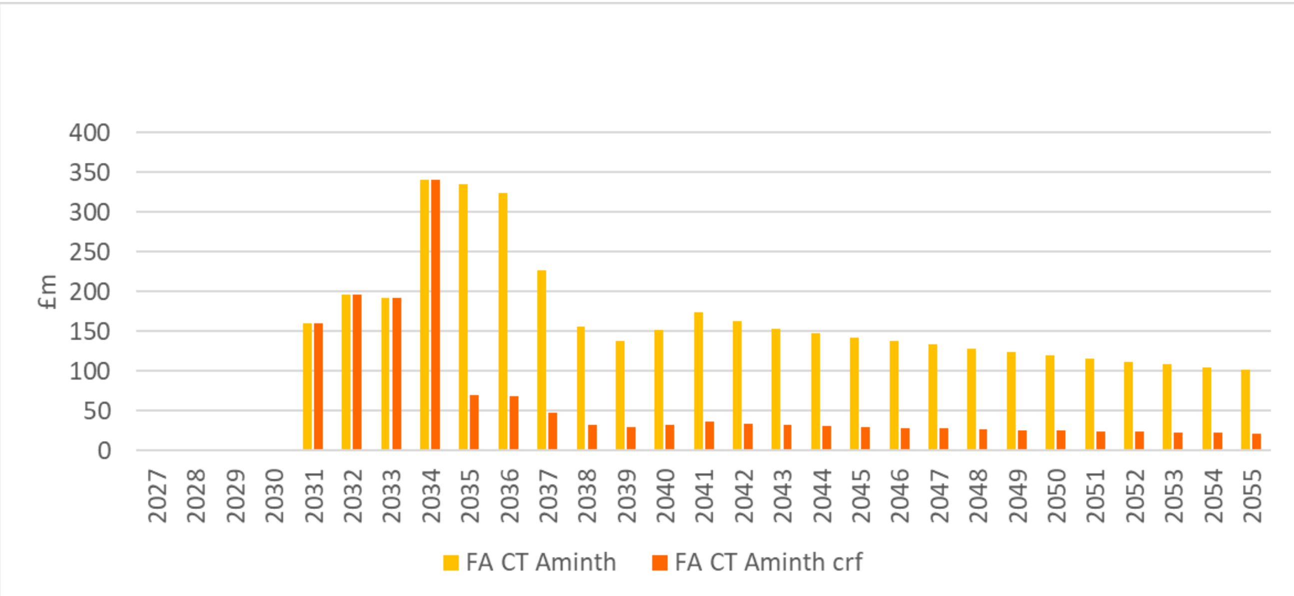
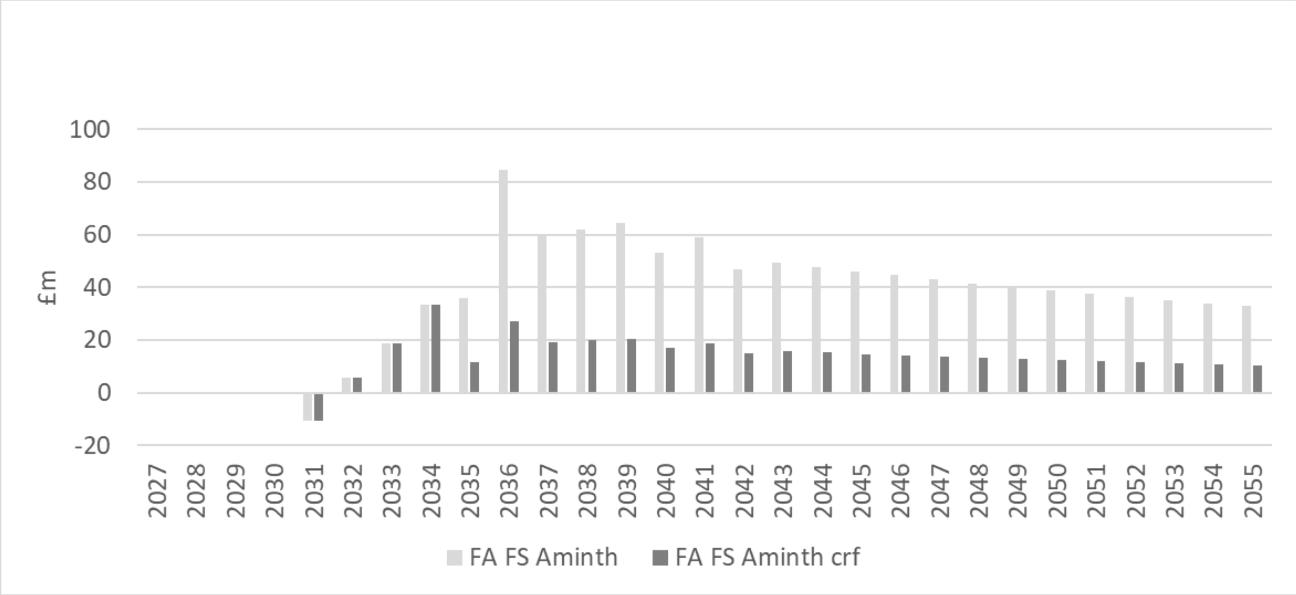
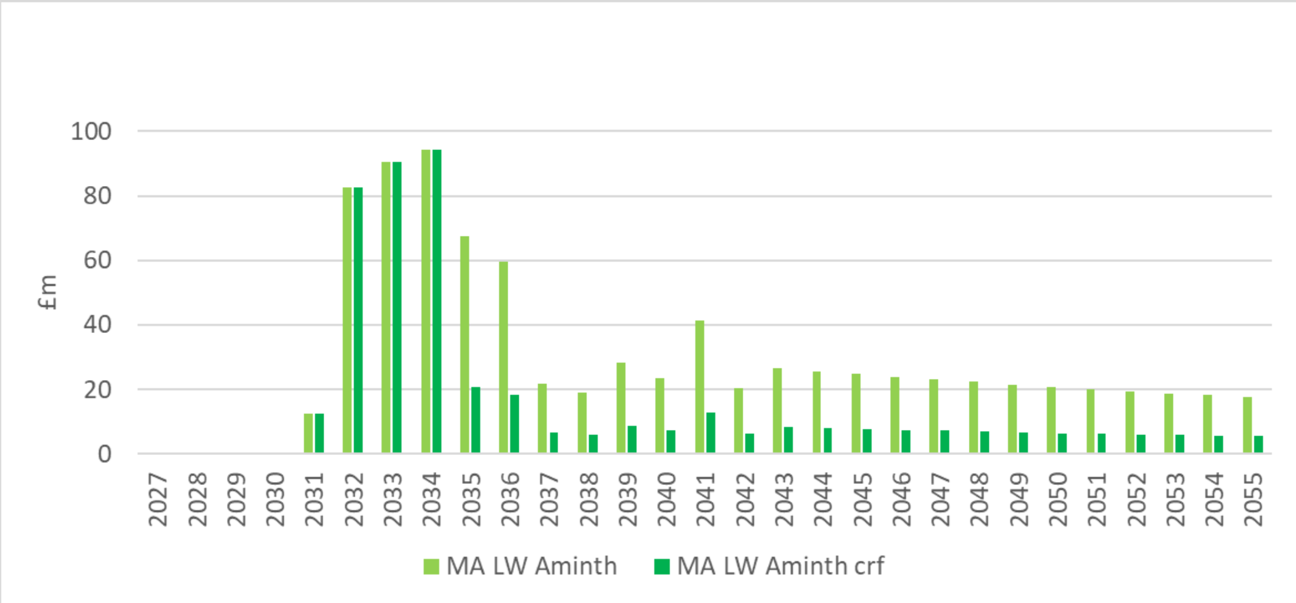


Figure 45: Additional annual constraint costs (discounted) due to Aminth for the First Additional case for Falling Short, without and with Constraint Reduction Factor applied.



The above chart shows the additional constraint costs without and with the Constraint Reduction Factor (CRF) applied. The chart shows the impact of the CRF being applied from 2035 onwards. As the years prior to 2035 show relatively lower additional constraint costs than those after 2035, the impact of the CRF is more pronounced than for the Leading the Way scenario.

Figure 46: Additional annual constraint costs (discounted) due to Aminth for the Marginal Additional case for Leading the Way, without and with Constraint Reduction Factor applied.



The above chart shows the additional constraint costs without and with the Constraint Reduction Factor (CRF) applied for the Leading the Way scenario for the Marginal Additional case. The chart shows the impact of the CRF being applied from 2035 onwards.

Figure 47: Additional annual constraint costs (discounted) due to Aminth for the Marginal Additional case for Consumer Transformation, without and with Constraint Reduction Factor applied.

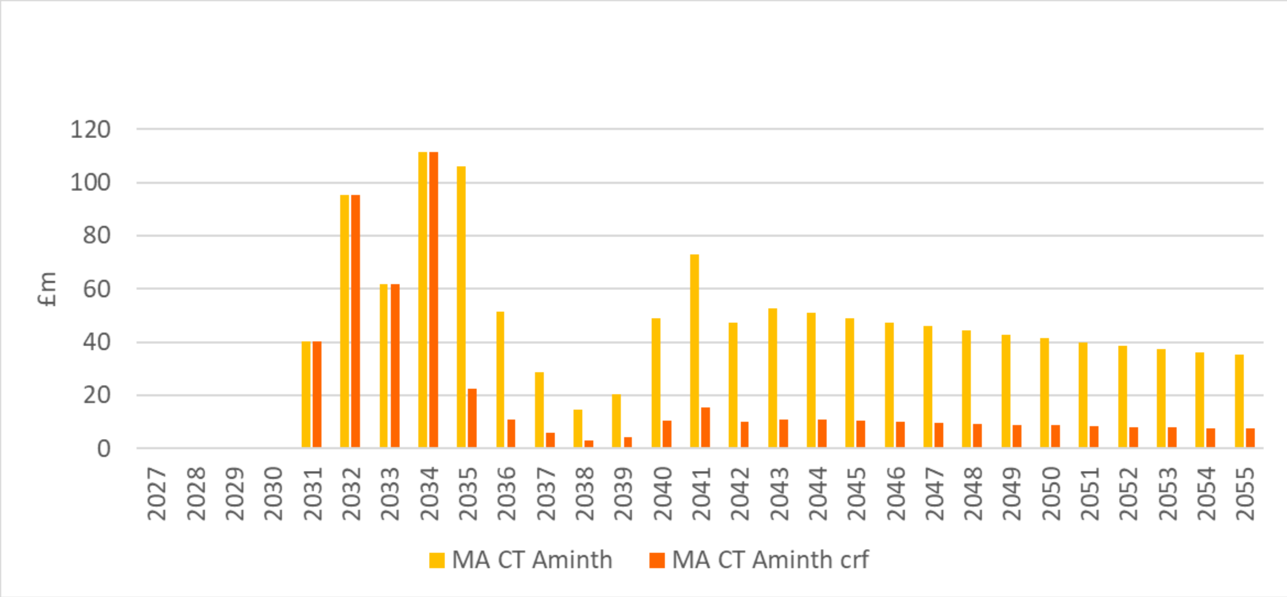
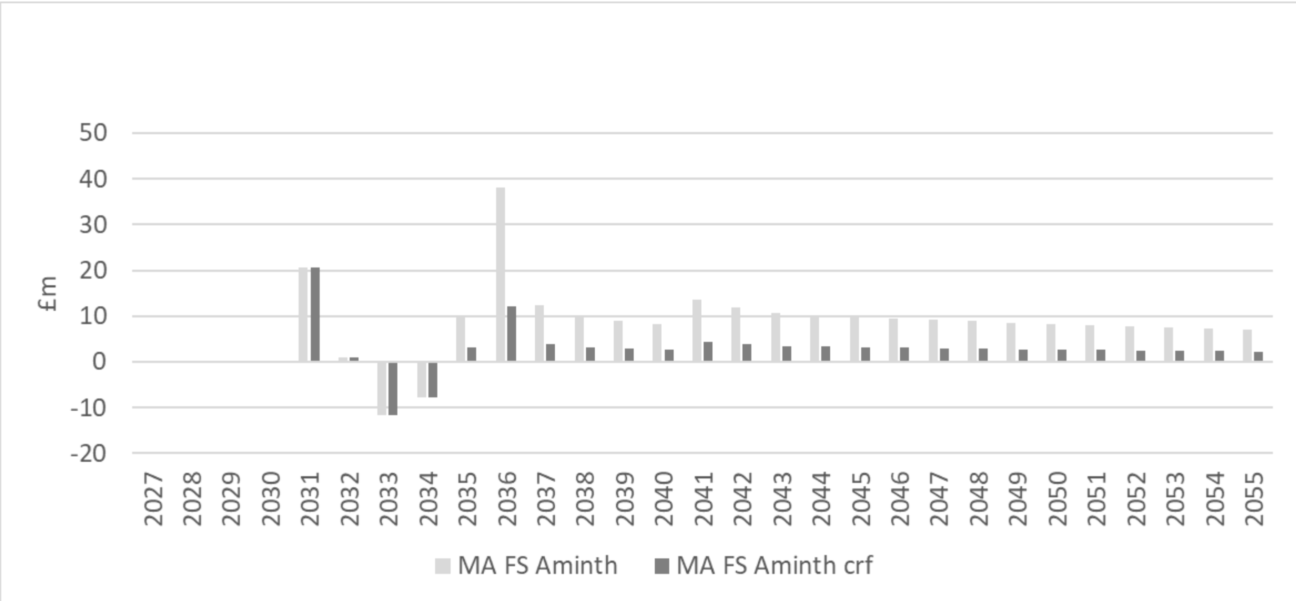
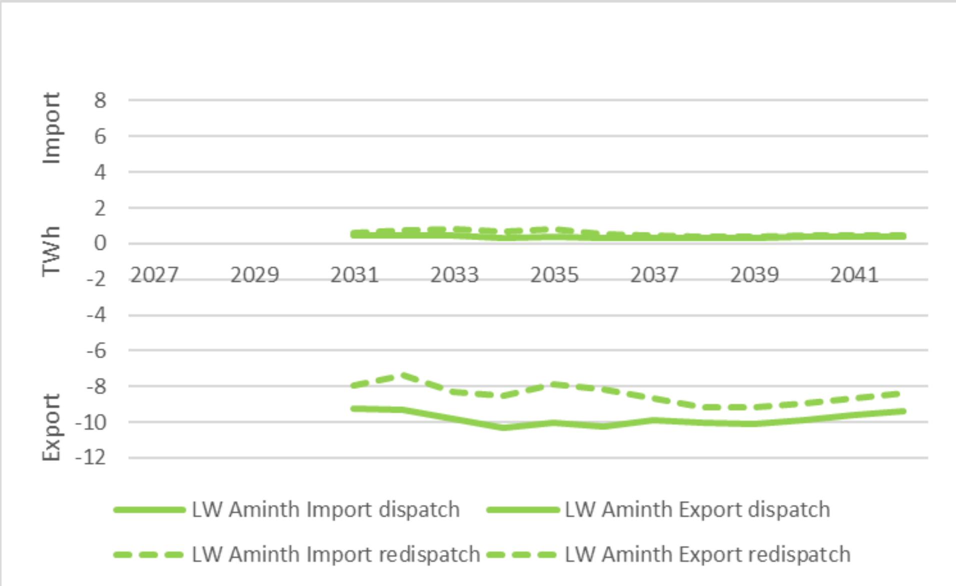


Figure 48: Additional annual constraint costs (discounted) due to Aminth for the First Additional case for Falling Short, without and with Constraint Reduction Factor applied.



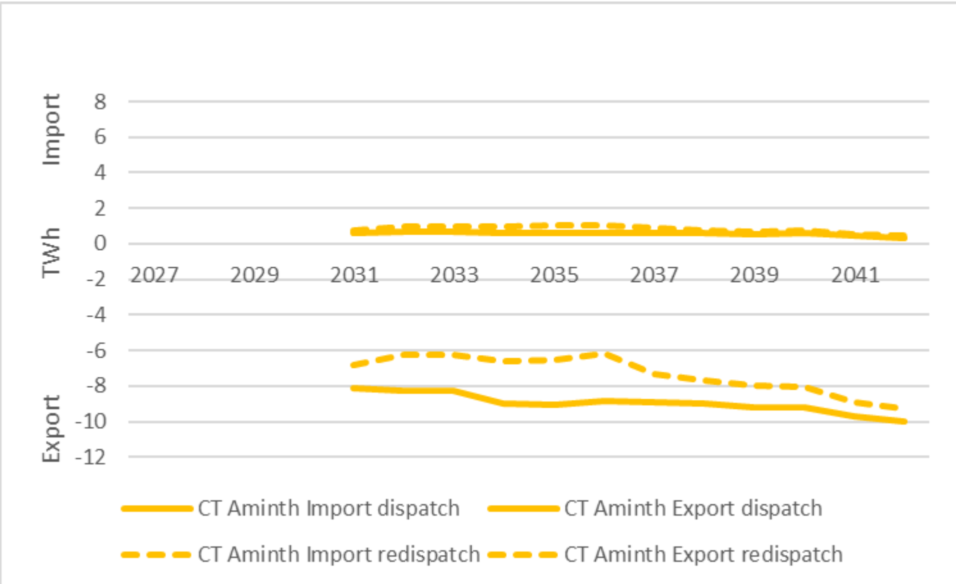
Annual import and export flows for dispatch and redispatch

Figure 49: Annual import and export flows for Aminth in the FA case for Leading the Way.



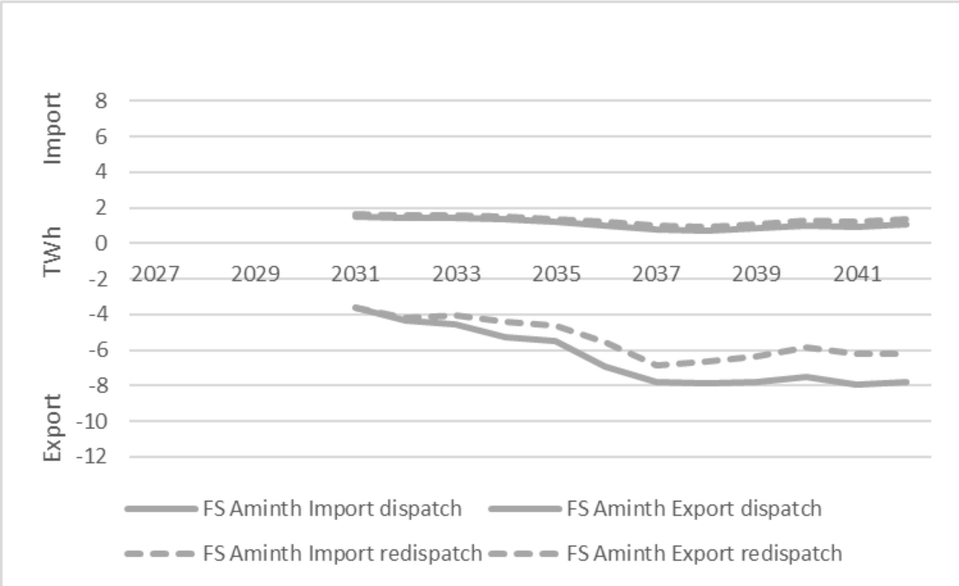
The above figure shows high exports and low imports in the dispatch. The redispatch shows a reduction in exports and a very slight increase in imports. Compared to the original (March 2024) results, exports are higher and imports are lower.

Figure 50: Annual import and export flows for Aminth in the FA case for Consumer Transformation.



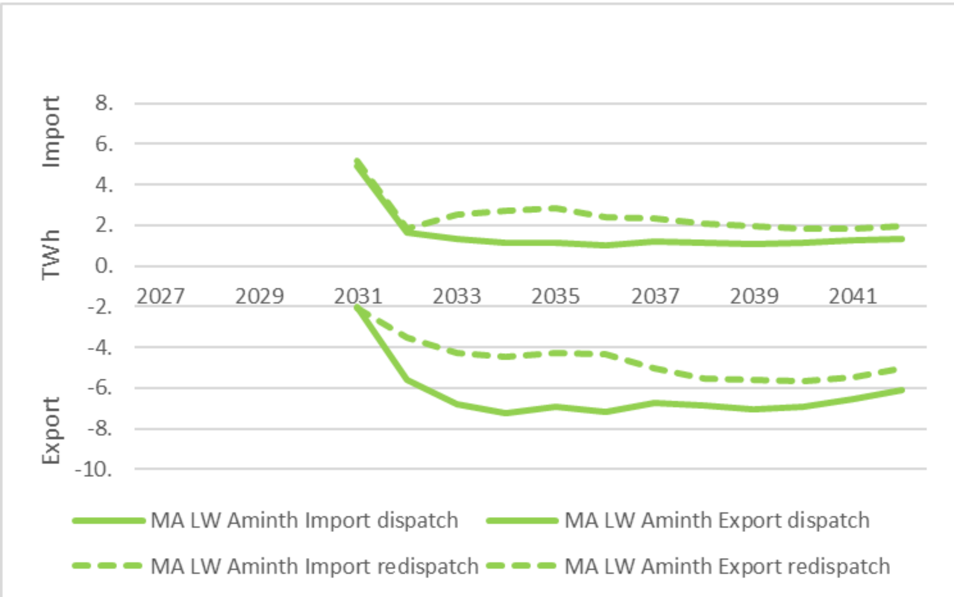
The above figure shows high exports and low imports in the dispatch. The redispatch shows a reduction in exports and a very slight increase in imports. Compared to the original (March 2024) results, exports are higher and imports are lower.

Figure 51: Annual import and export flows for Aminth in the FA case for Falling Short.



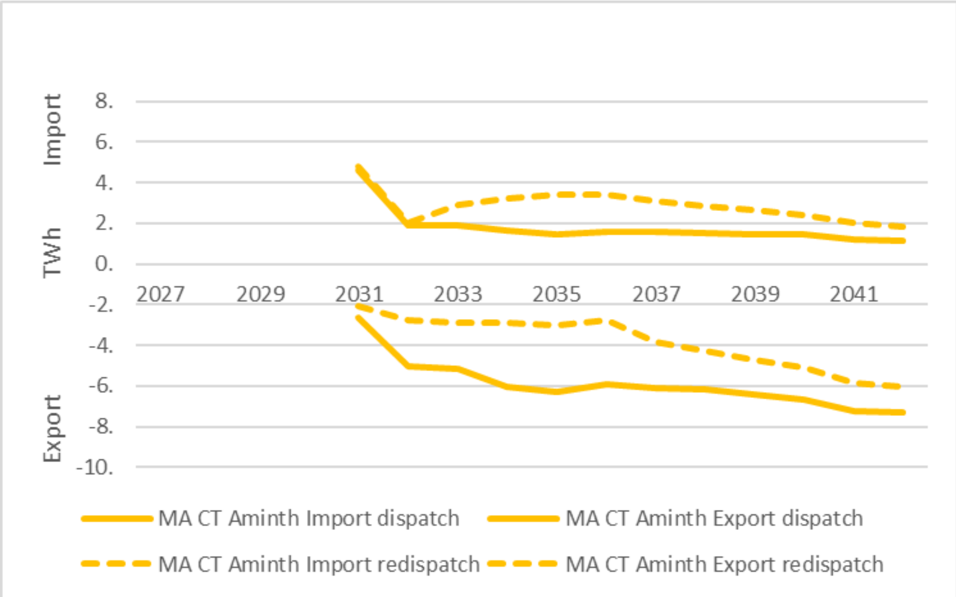
The above figure shows that for the First Additional case Aminth has increasing levels of exports over the forecast period up to 2038 for Falling Short. The redispatch shows a reduction in exports after 2033. Compared to the original (March 2024) results, exports are higher and imports are lower.

Figure 52: Annual import and export flows for Aminth in the MA case for Leading the Way.



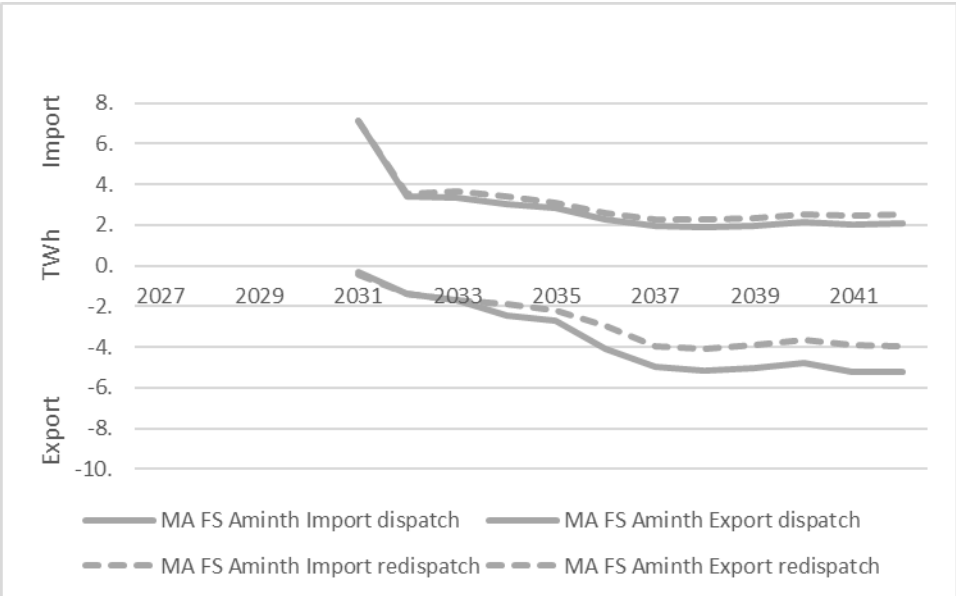
The above figure shows for the dispatch high exports, but lower than in the FA case, and low imports, but higher than in the FA case. The redispatch shows a significant reduction in exports and an increase in imports. Compared to the original (March 2024) results, exports are higher and imports are similar.

Figure 53: Annual import and export flows for Aminth in the MA case for Consumer Transformation.



The above figure shows high exports, but lower than in the FA case, and low imports in the dispatch. The redispatch shows exports reduced significantly in the early to mid-2030s and an increase in imports. Compared to the original (March 2024) results, exports are slightly higher and imports are similar.

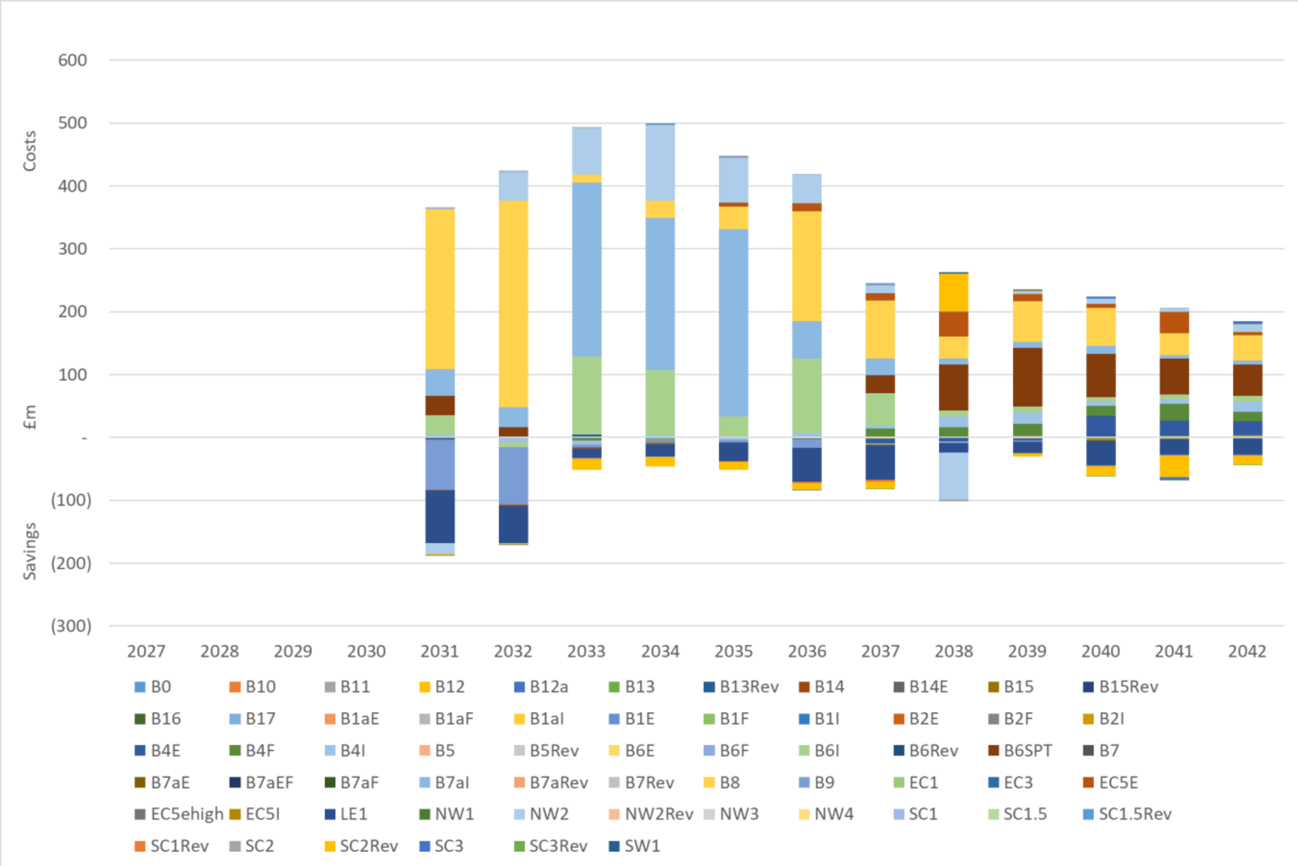
Figure 54: Annual import and export flows for Aminth in the MA case for Falling Short.



The above figure shows that for the Marginal Additional case, Aminth has increasing exports, but lower than in the First Additional case, and decreasing imports in the dispatch, which are higher than those in FA. The redispatch shows some reduction in exports, especially in the later years and a very small increase in imports. Compared to the original (March 2024) results, exports and imports are very similar.

Change in constraint costs by boundary

Figure 55: Change in constraint costs by boundary for Aminth for the First Additional case for Leading the Way.



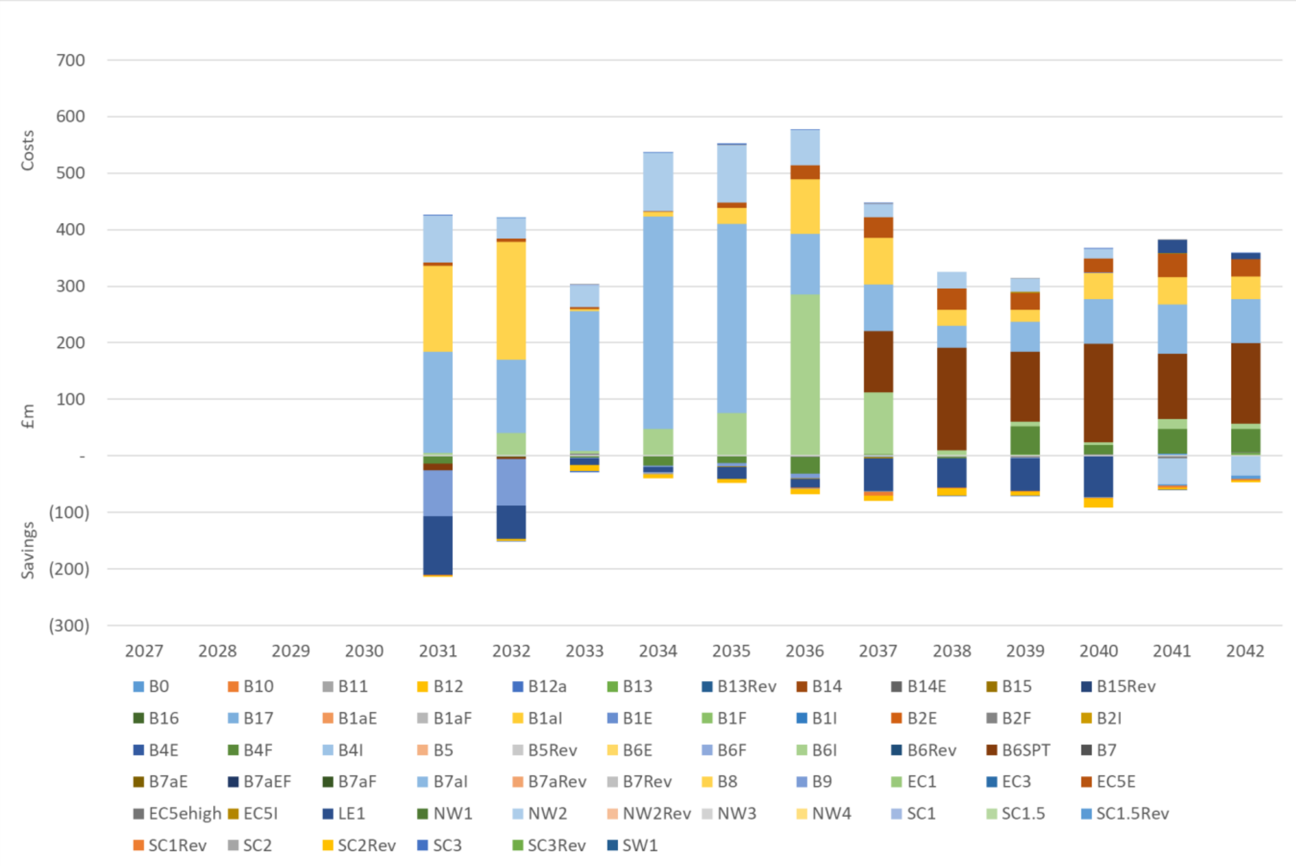
The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for Aminth for the First Additional case for the Leading the Way scenario. Each different colour represents the change in constraint costs for a particular boundary. It is important to note that the chart shows changes in constraint costs by boundary, i.e. the difference between constraint costs when the project is included and when the project is excluded.

The figure shows that Aminth increases constraint costs on certain boundaries but also reduces constraint costs on others. Whether the impact is an increase in constraint costs or a reduction in constraint costs for a particular boundary, changes from year to year. The size of change in constraint costs by boundary can also vary significantly from year to year. This is shown clearly in the years 2036 to 2037. The figure also shows that the specific boundaries that have the greatest impact on the total change in constraint costs can vary from year to year. These factors are a result of the changes in demand, supply and network capability over time.

In general, Aminth increases constraint costs on several northern boundaries, but relieves congestion on certain midland and southern boundaries in the early years. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis, constraint costs are higher on several northern boundaries.

Figure 56: Change in constraint costs by boundary for Aminth for the First Additional case for Consumer Transformation.

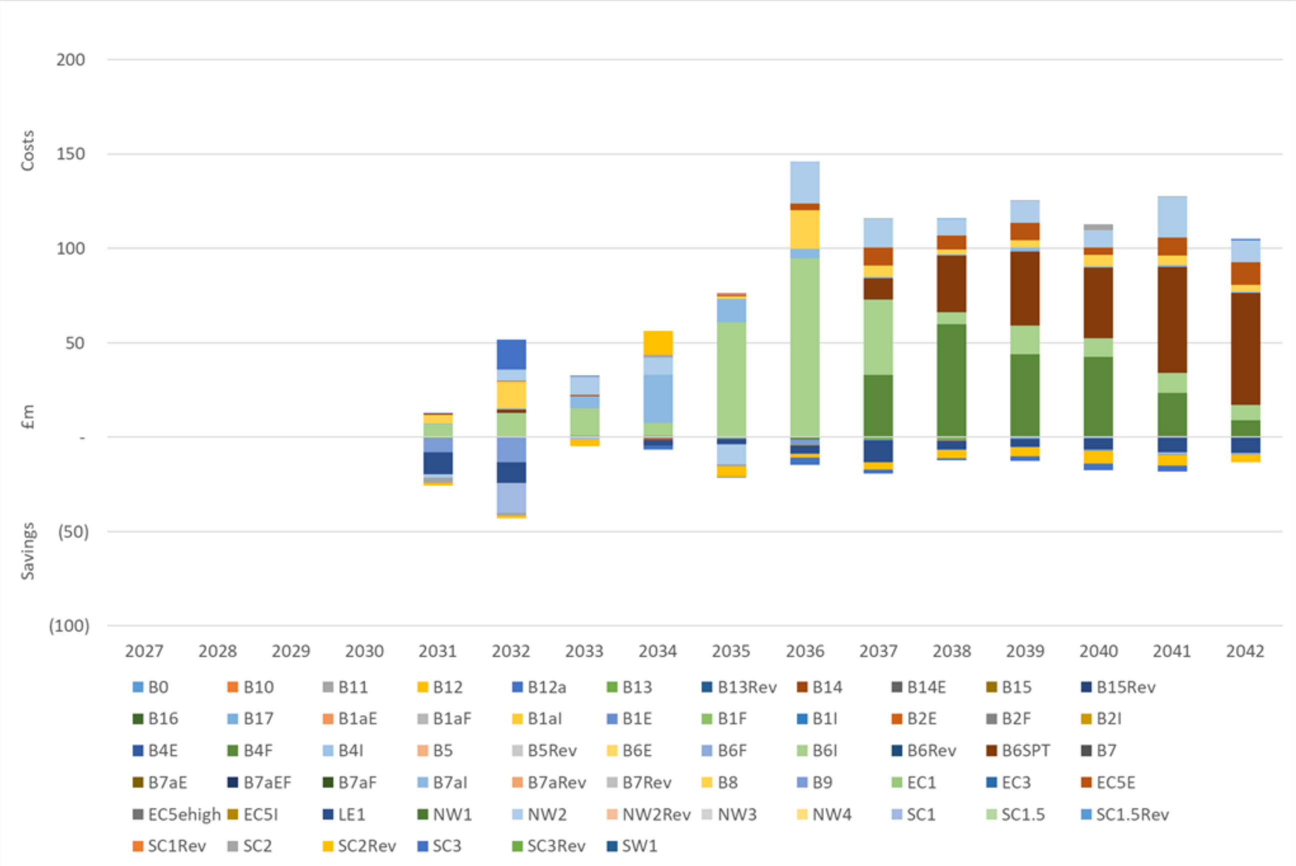


The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for Aminth for the First Additional case for the Consumer Transformation scenario.

In general, Aminth increases constraint costs on several northern boundaries, but relieves congestion on certain midland and southern boundaries in the early years. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis, constraint costs are higher on several northern boundaries.

Figure 57: Change in constraint costs by boundary for Aminth for the First Additional case for Falling Short.

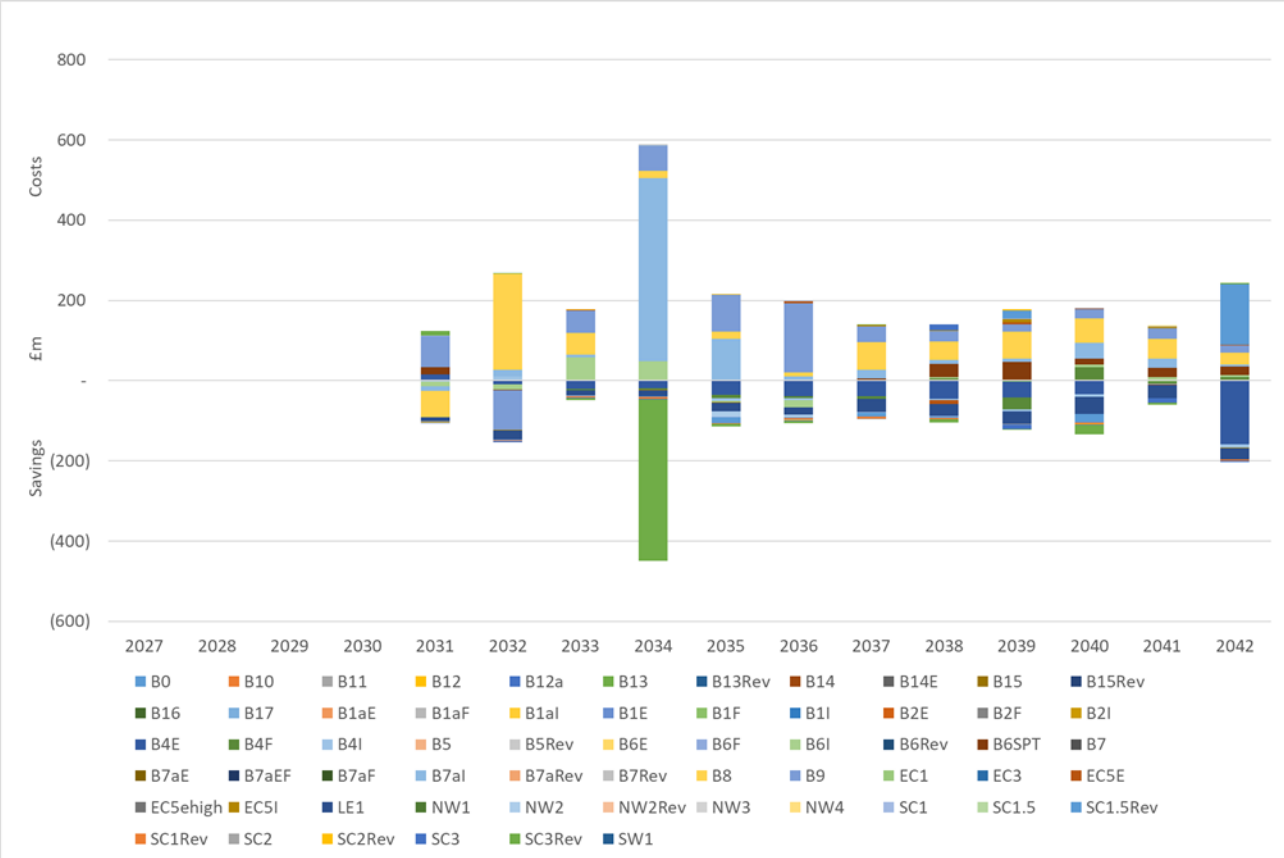


The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for Aminth for the First Additional case for the Falling Short scenario.

In general, Aminth increases constraint costs on several northern boundaries, but relieves congestion on certain midland and southern boundaries in the early years. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis, constraint costs are higher on several northern boundaries.

Figure 58: Change in constraint costs by boundary for Aminth for the Marginal Additional case for Leading the Way.

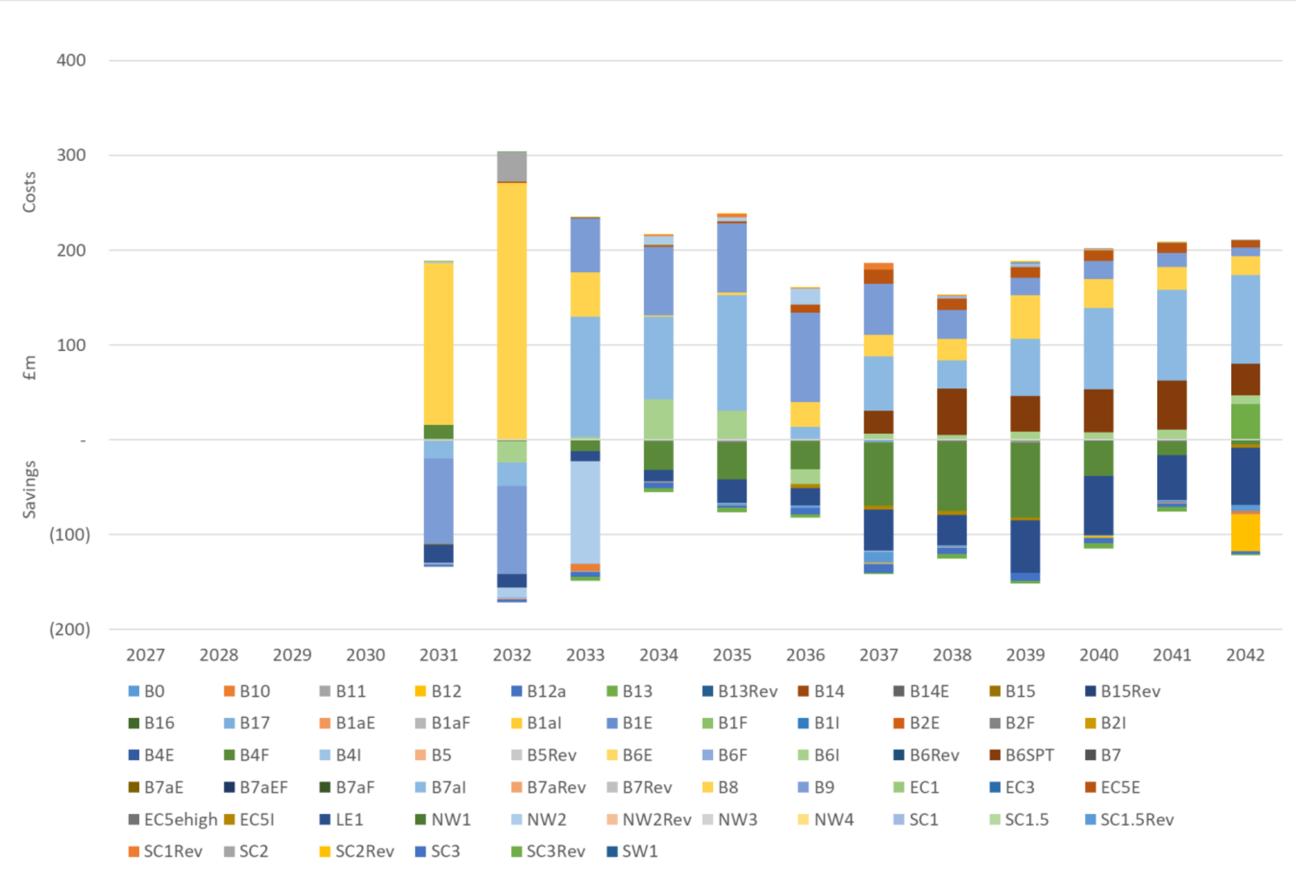


The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for Aminth for the Marginal Additional case for the Leading the Way scenario.

In general, Aminth increases constraint costs on several northern boundaries, but relieves congestion on certain midland and southern boundaries in the early years. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis, constraint costs are higher on several northern boundaries.

Figure 59: Change in constraint costs by boundary for Aminth for the Marginal Additional case for Consumer Transformation.

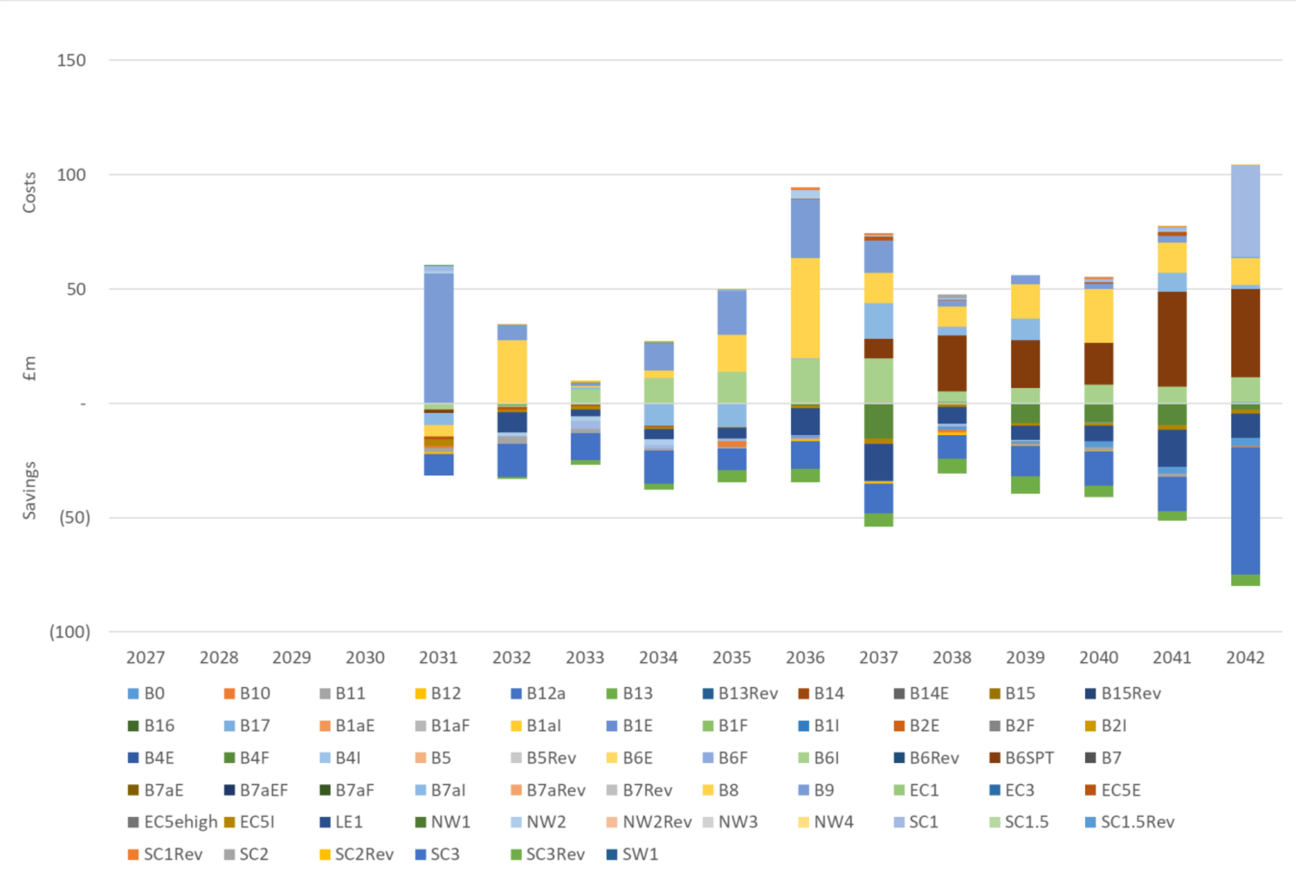


The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for Aminth for the Marginal Additional case for the Consumer Transformation scenario.

In general, Aminth increases constraint costs on several northern boundaries, but relieves congestion on certain midland and southern boundaries in the early years. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis, constraint costs are higher on several northern boundaries, as well as less savings on several southern boundaries.

Figure 60: Change in constraint costs by boundary for Aminth for the Marginal Additional case for Falling Short.



The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for Aminth for the Marginal Additional case for the Falling Short scenario.

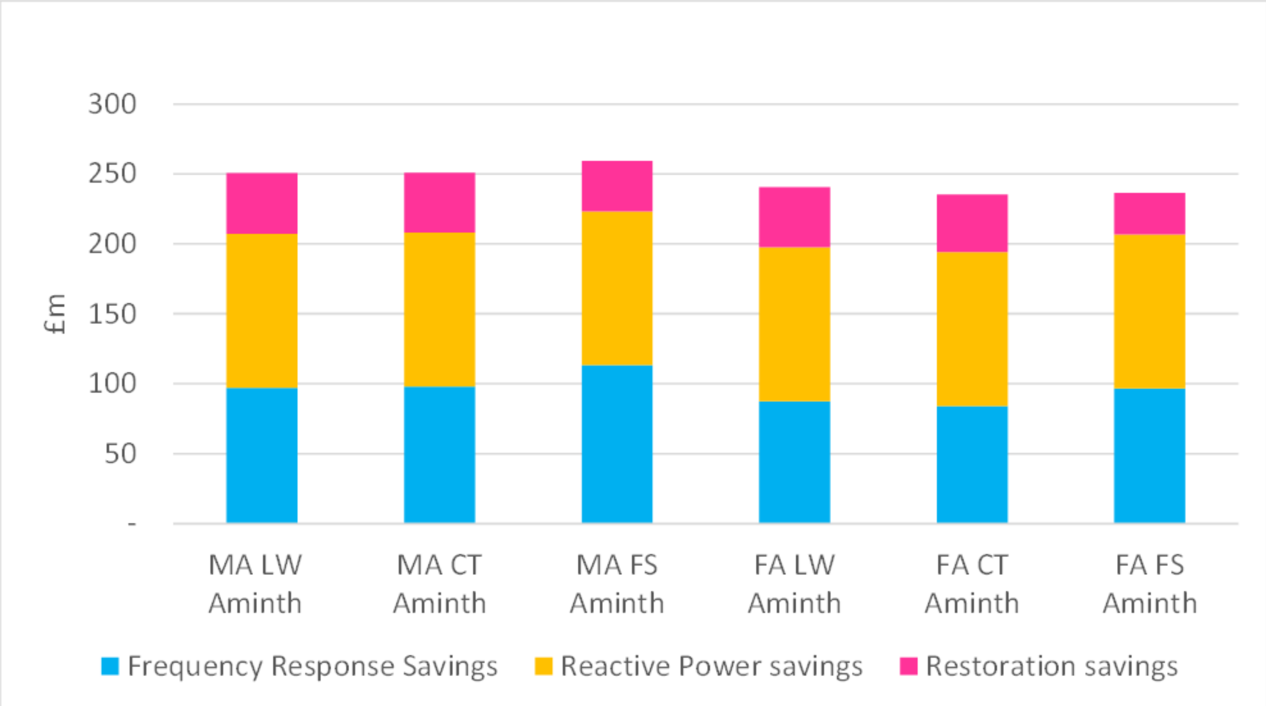
In general, Aminth increases constraint costs on several northern boundaries, but relieves congestion on certain southern boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis, constraint costs are higher on several northern boundaries, as well as increased savings on several southern boundaries.

PV system operation

Note: The modelling and analysis for system operation is the same as that within the March 2024 report. It was not necessary to repeat the work because the change in modelling assumptions would not produce a material change in the results.

Figure 61: PV potential system operability savings for Aminth, Present Value 25-year, real 2022, £m.

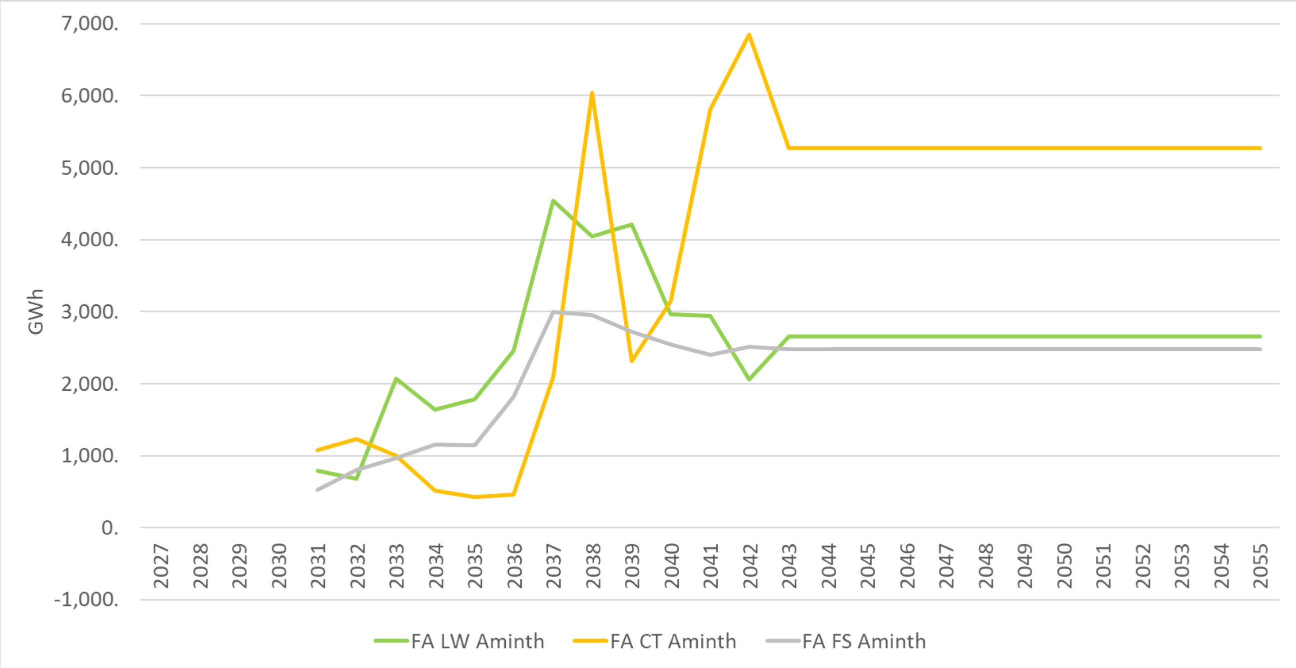


The above figure shows the potential savings for frequency response, reactive power and restoration services in present value (25-year, 2022 £m) for Aminth for Leading the Way, Consumer Transformation and Falling Short for both the Marginal Additional and First Additional cases. There is considerable uncertainty around forecasting potential system operability benefits over a 25-year time horizon, but the figure shows that there is potentially significant savings in frequency response, reactive power and restoration services.

There is little variation across the three scenarios and also across the First Additional and Marginal Additional cases. This is because the potential system operability savings from the services provided by Aminth are less sensitive to flows across the interconnector, whereas the constraint cost impact is highly dependent on the scale and direction of flows across the project.

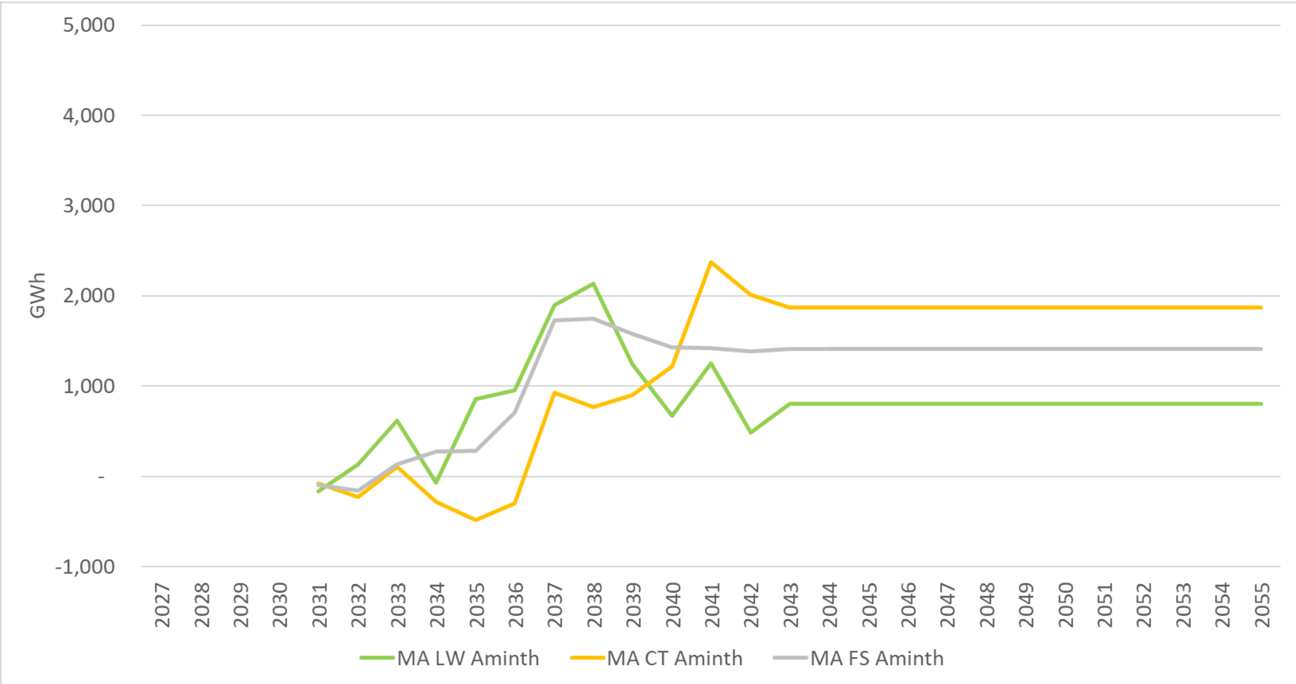
RES curtailment avoided

Figure 62: Annual RES curtailment avoided for Aminth for the First Additional case.



The above figure shows the renewable energy supply (RES) curtailment avoided on an annual basis for Leading the Way, Consumer Transformation and Falling Short for the First Additional case. Note that beyond 2042, the results are an average of the years 2040, 2041 and 2042, as our detailed modelling with FES22 only extends out to 2042. The figure shows that the level of annual RES curtailment avoided when Aminth is included is approximately between 1TWh and 5TWh, which equates to approximately between 2.7GWh and 13.7GWh per day.

Figure 63: Annual RES curtailment avoided for Aminth for the Marginal Additional case.



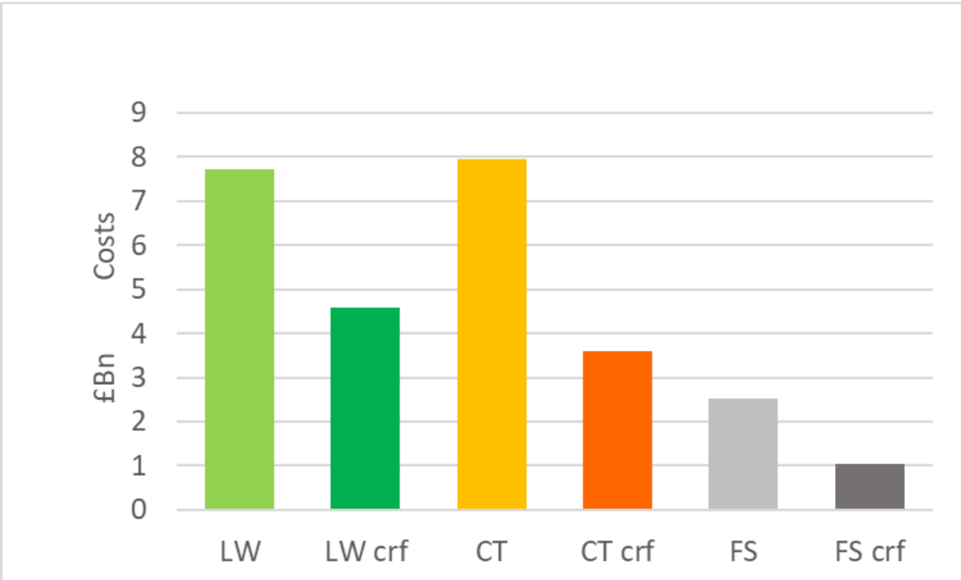
The above figure shows the renewable energy supply (RES) curtailment avoided on an annual basis for Leading the Way, Consumer Transformation and Falling Short for the Marginal Additional case. Note that beyond 2042, the results are an average of the years 2040, 2041 and 2042, as our detailed modelling with FES22 only extends out to 2042. The figure shows that the level of annual RES curtailment avoided when Aminth is included rises to approximately between 1TWh and 2TWh, which equates to approximately between 2.7GWh and 5.5GWh per day.

11. AQUIND

AQUIND is a W3 interconnector project. It has a capacity of 2.0GW and connects to France.

PV constraint costs

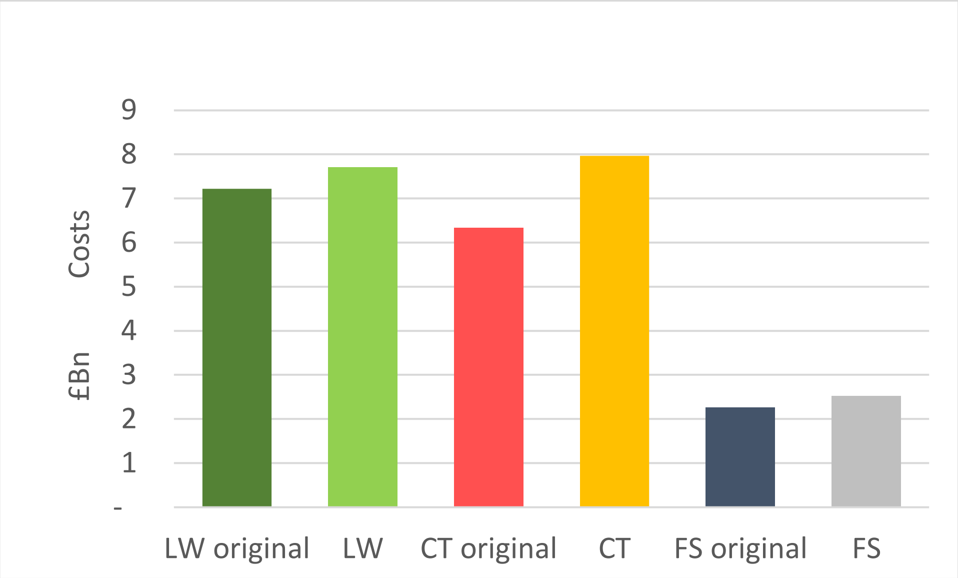
Figure 64: PV additional constraint costs due to AQUIND for the First Additional case, Present Value 25-year, real 2022, £m, without and with Constraint Reduction Factor applied.



The above figure shows the additional constraint costs with the inclusion of AQUIND for the FA case. Without the Constraint Reduction Factor applied, in the Leading the Way scenario (LW) constraint costs are increased by £7.7bn, in Consumer Transformation (CT) by £8.0bn and in the Falling Short (FS) scenario by £2.5bn.

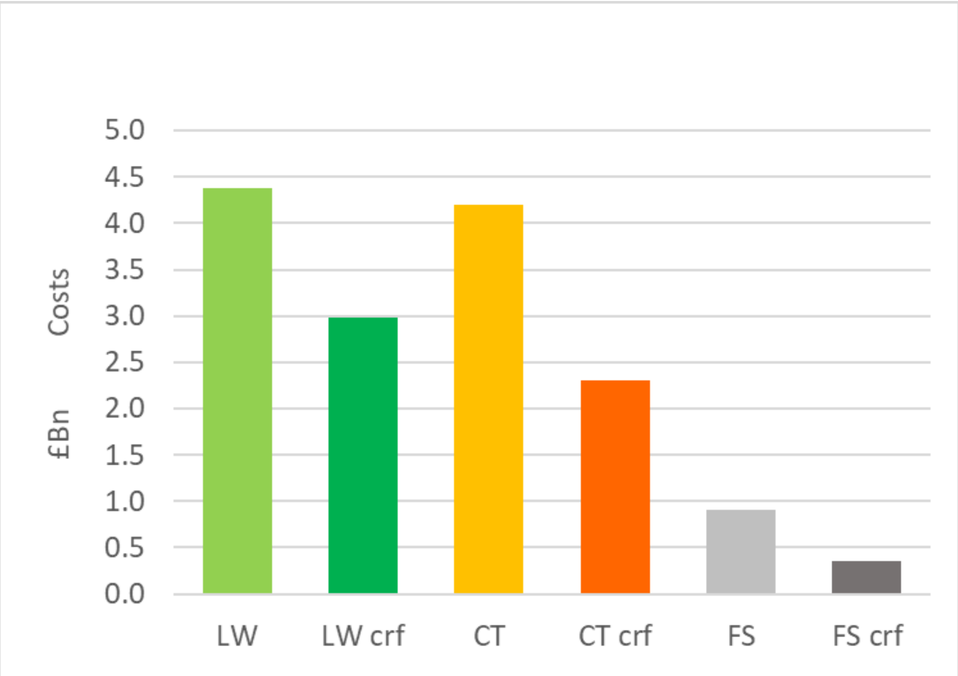
With the Constraint Reduction Factor applied, in the Leading the Way scenario (LW) constraint costs are increased by £4.6bn, in Consumer Transformation (CT) by £3.6bn and in the Falling Short (FS) scenario by £1.0bn.

Figure 65: PV additional constraint costs due to AQUIND for the First Additional case, Present Value 25-year, real 2022, £m, for the original analysis (March 2024) and for Nautilus at Grain with 1.4GW link and Irish demand and generation from TYNDP.



The above figure shows that the changes made to the scenarios, that is the reduction in the capacity of the link connecting the Nautilus offshore platform to Belgium from 3.5GW to 1.4GW and the change in Irish demand and generation to reflect final TYNDP data results in an increase in constraint costs in all three scenarios, with CT showing the largest increase.

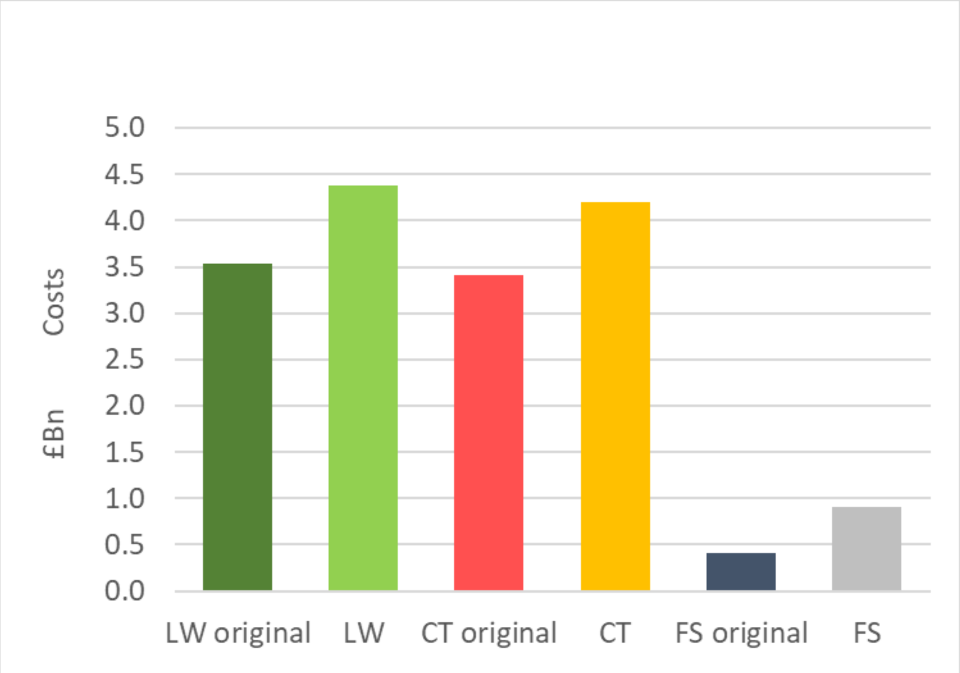
Figure 66: PV additional constraint costs due to AQUIND for the Marginal Additional case, Present Value 25-year, real 2022, £m, without and with Constraint Reduction Factor applied.



The above figure shows the additional constraint costs with the inclusion of AQUIND for the MA case. Without the Constraint Reduction Factor applied, in the Leading the Way scenario (LW) constraint costs are increased by £4.4bn, in Consumer Transformation (CT) by £4.2bn and in the Falling Short (FS) scenario by £0.9bn.

With the Constraint Reduction Factor applied, in the Leading the Way scenario (LW) constraint costs are increased by £3.0bn, in Consumer Transformation (CT) by £2.3bn and in the Falling Short (FS) scenario by £0.35bn

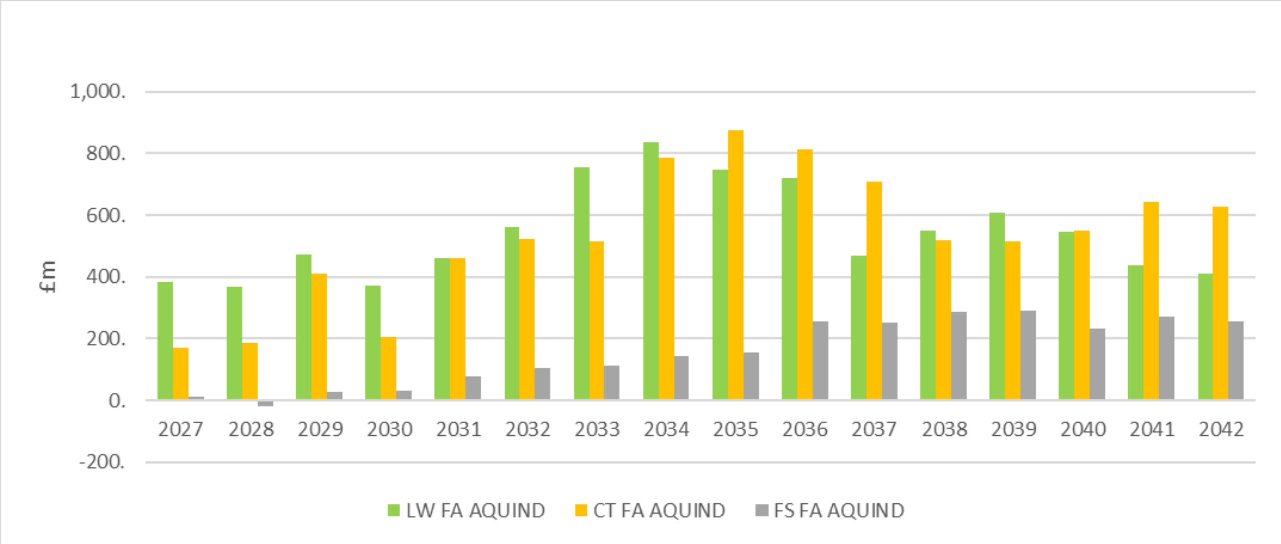
Figure 67: PV additional constraint costs due to AQUIND for the Marginal Additional case, Present Value 25-year, real 2022, £m, for the original analysis (March 2024) and for Nautilus at Grain with 1.4GW link and Irish demand and generation from TYNDP.



The above figure shows that the changes made to the scenarios, that is the reduction in the capacity of the link connecting the Nautilus offshore platform to Belgium from 3.5GW to 1.4GW and the change in Irish demand and generation to reflect final TYNDP data results in an increase in constraint costs in all three scenarios.

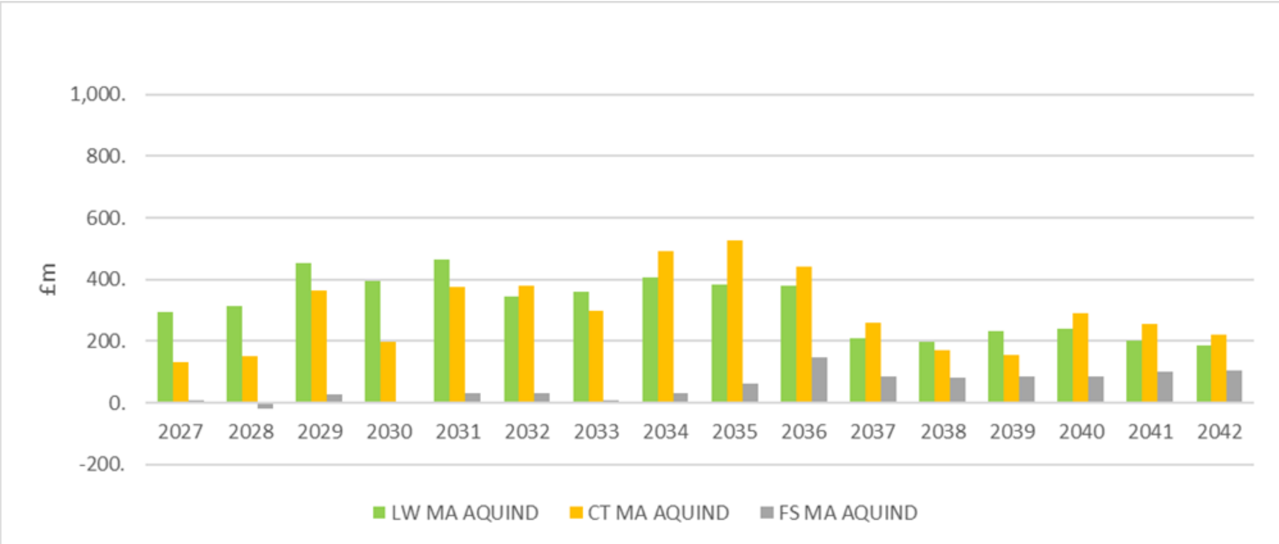
Annual constraint costs (undiscounted)

Figure 68: Additional annual constraint costs (undiscounted) due to AQUIND for the First Additional case.



The above figure shows that AQUIND results in an increase in constraint costs of approximately £400m to £800m (undiscounted) in CT and LW for the years 2031 to 2042. In FS constraint cost increases are much lower, with small savings in 2028. The results are higher than the original (March 2024) results.

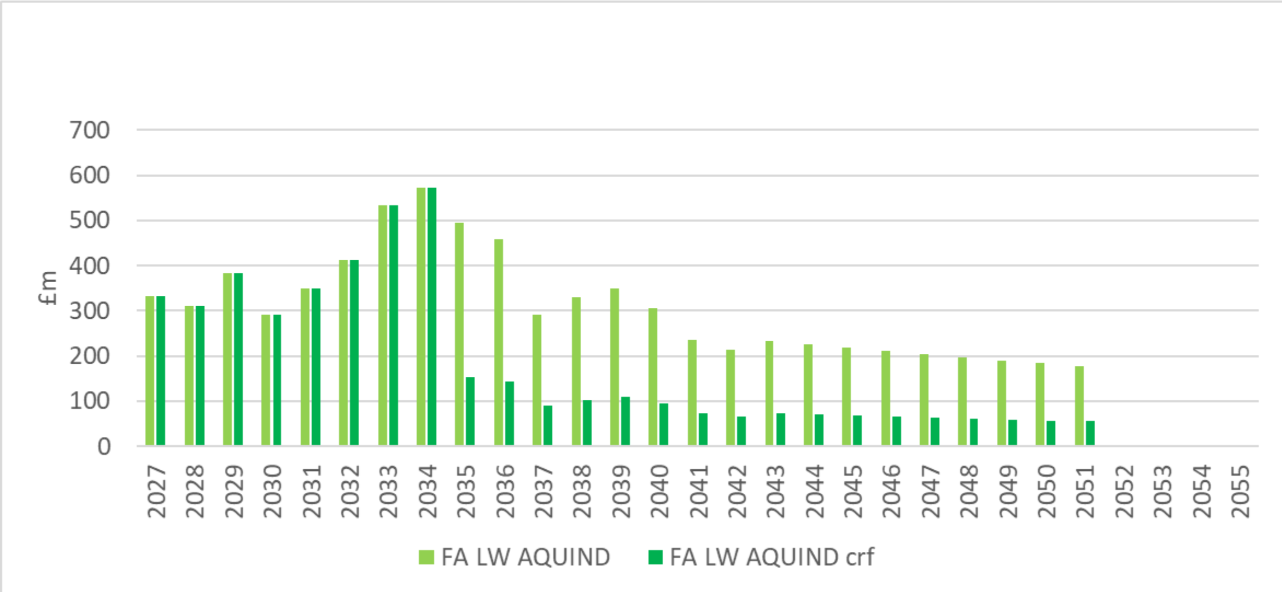
Figure 69: Additional annual constraint costs (undiscounted) due to AQUIND for the Marginal Additional case.



In the Marginal Additional case, AQUIND results in an increase in constraint costs of approximately £200m to £500m (undiscounted) in CT and LW for the years 2029 to 2036. FS shows a small constraint saving for the year 2028, and for the other years shows much lower levels of additional constraint costs compared to LW and CT. The results for all three scenarios are higher than the original (March 2024) results.

Annual constraint costs (discounted), without and with Constraint Reduction Factor

Figure 70: Additional annual constraint costs (discounted) due to AQUIND for the First Additional case for Leading the Way, without and with Constraint Reduction Factor applied.



The above chart shows the additional constraint costs without and with the Constraint Reduction Factor (CRF) applied for the Leading the Way scenario for the First Additional case. The chart shows the impact of the CRF being applied from 2035 onwards.

Figure 71: Additional annual constraint costs (discounted) due to AQUIND for the First Additional case for Consumer Transformation, without and with Constraint Reduction Factor applied.

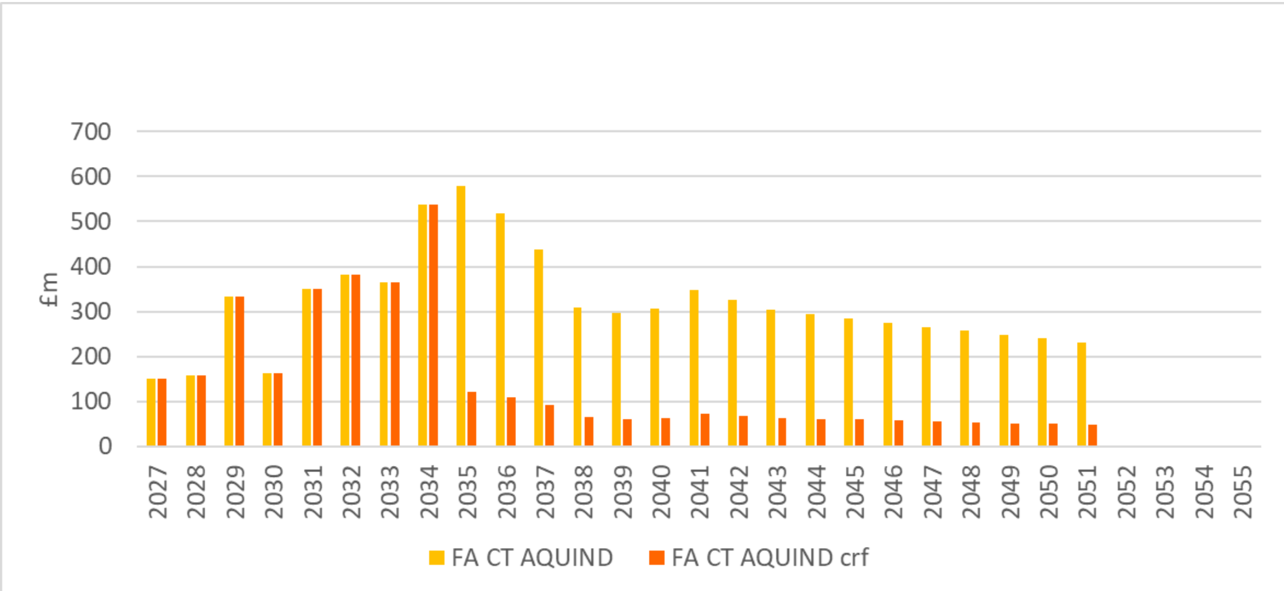
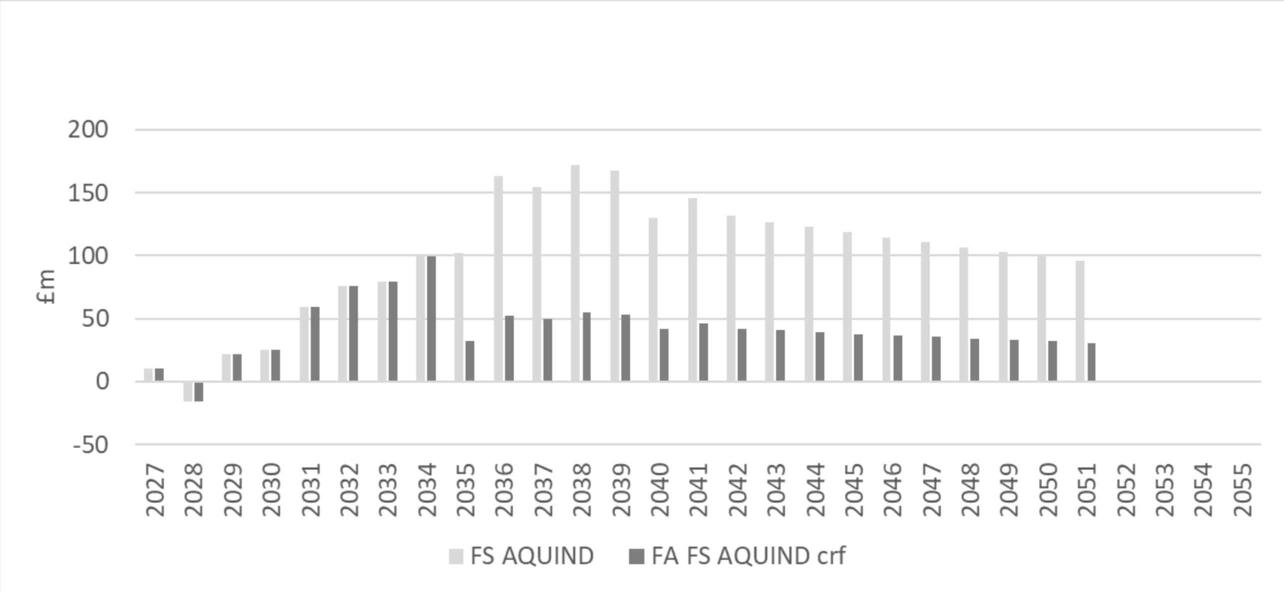
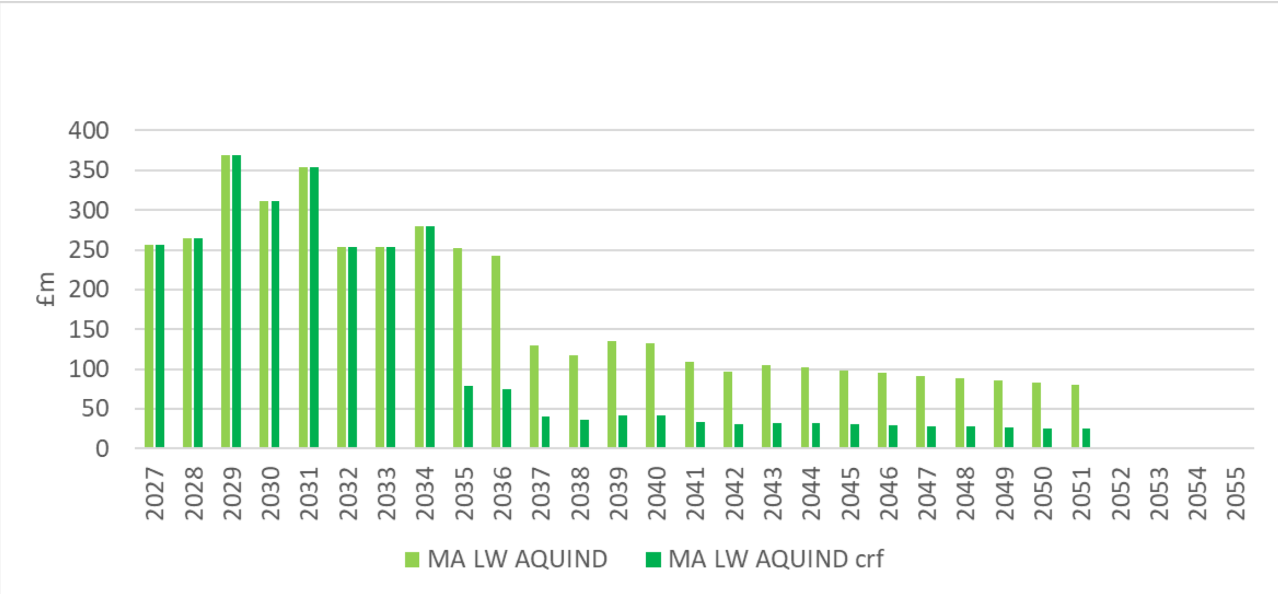


Figure 72: Additional annual constraint costs (discounted) due to AQUIND for the First Additional case for Falling Short, without and with Constraint Reduction Factor applied.



The above chart shows the additional constraint costs without and with the Constraint Reduction Factor (CRF) applied. The chart shows the impact of the CRF being applied from 2035 onwards. As the years prior to 2035 show relatively lower additional constraint costs than those after 2035, the impact of the CRF is more pronounced than for the LW and CT scenario.

Figure 73: Additional annual constraint costs (discounted) due to AQUIND for the Marginal Additional case for Leading the Way, without and with Constraint Reduction Factor applied.



The above chart shows the additional constraint costs without and with the Constraint Reduction Factor (CRF) applied for the Leading the Way scenario for the Marginal Additional case. The chart shows the impact of the CRF being applied from 2035 onwards.

Figure 74: Additional annual constraint costs (discounted) due to AQUIND for the Marginal Additional case for Consumer Transformation, without and with Constraint Reduction Factor applied.

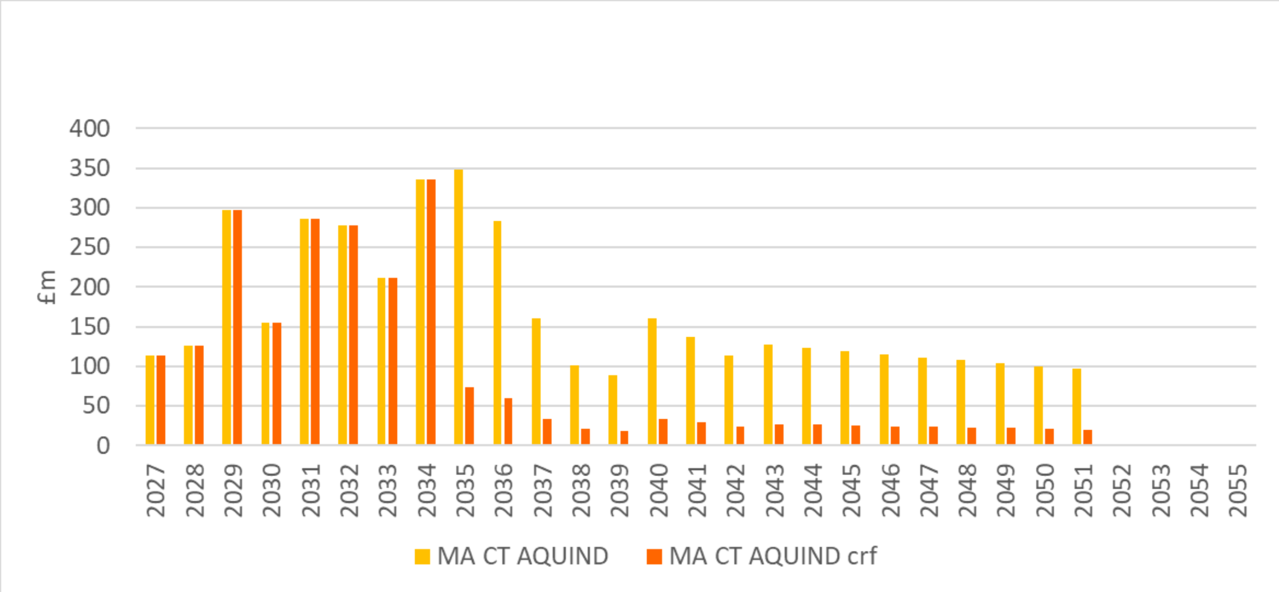
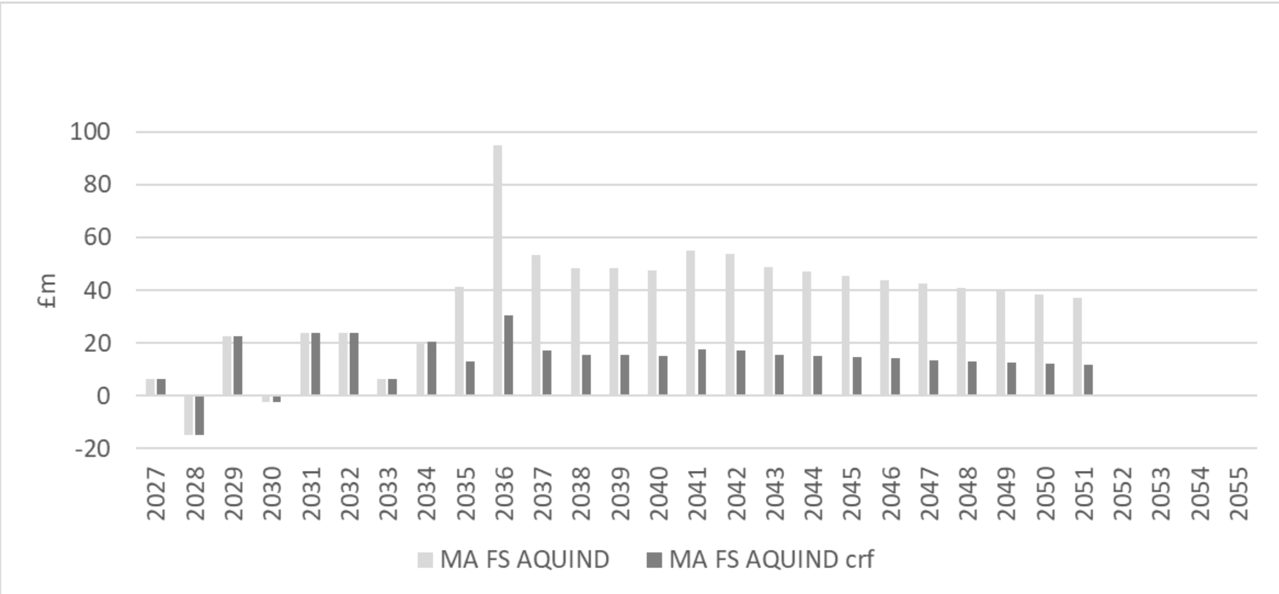
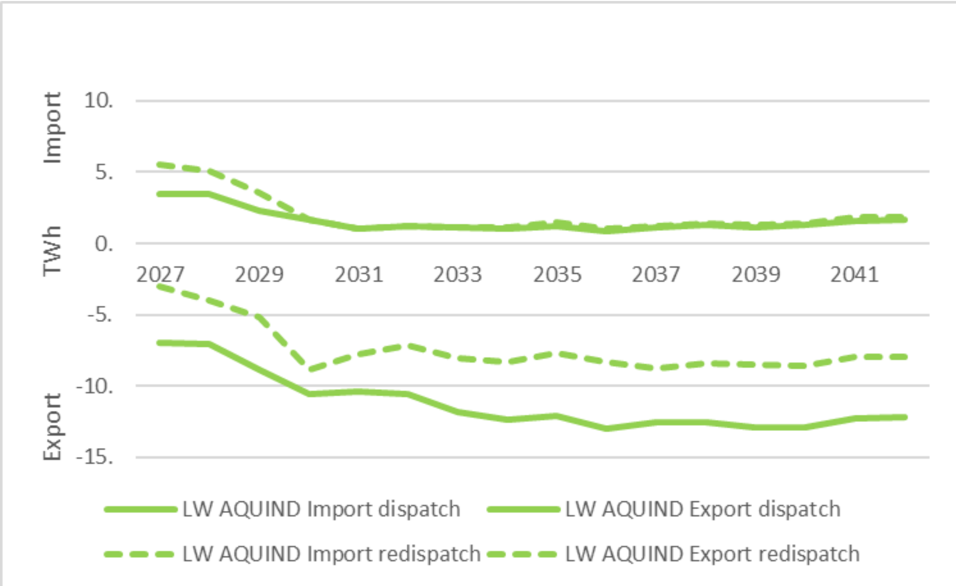


Figure 75: Additional annual constraint costs (discounted) due to AQUIND for the First Additional case for Falling Short, without and with Constraint Reduction Factor applied.



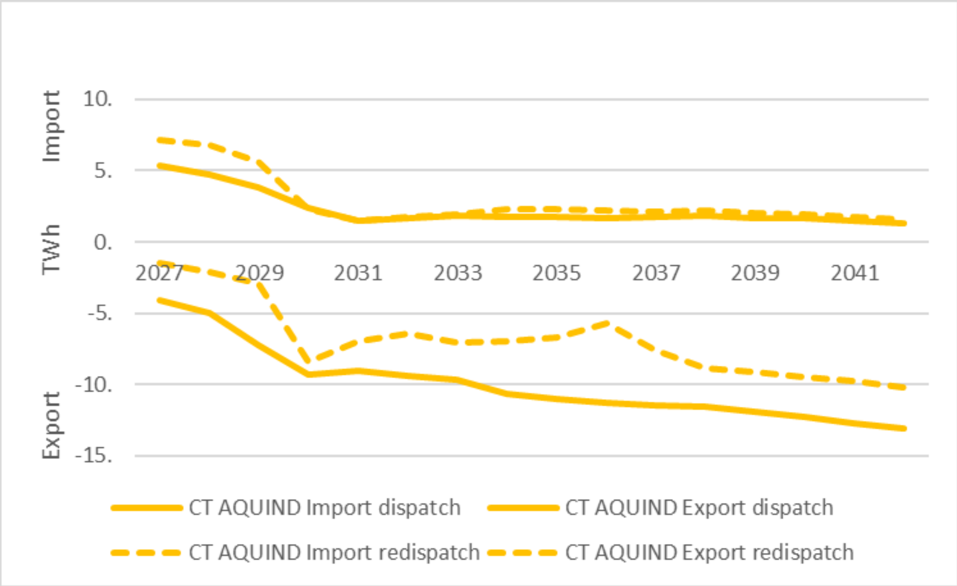
Annual import and export flows for dispatch and redispatch

Figure 76: Annual import and export flows for AQUIND in the FA case for Leading the Way.



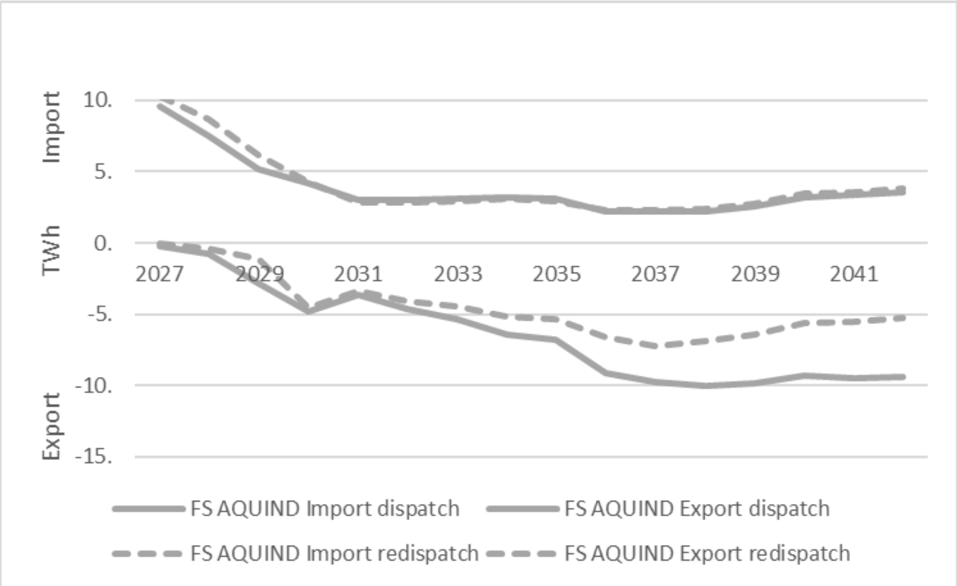
The above figure shows high exports and low imports in the dispatch. The redispatch shows a significant reduction in exports and a very slight increase in imports. Compared to the original (March 2024) results, exports and imports are very similar.

Figure 77: Annual import and export flows for AQUIND in the FA case for Consumer Transformation.



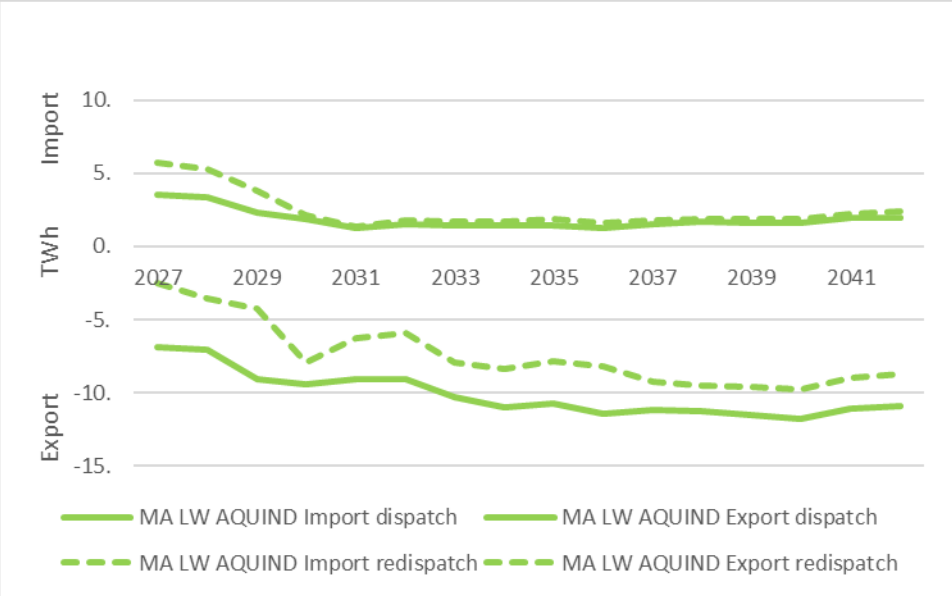
The above figure shows high exports and low imports in the dispatch. The redispatch shows a reduction in exports and a very slight increase in imports. Compared to the original (March 2024) results, exports and imports are similar.

Figure 78: Annual import and export flows for AQUIND in the FA case for Falling Short.



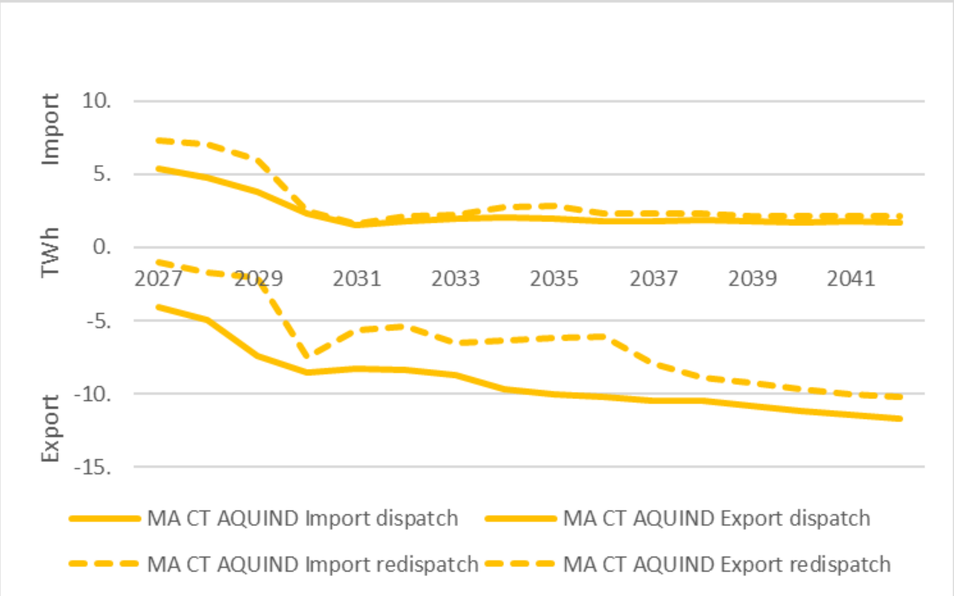
The above figure shows that for the First Additional case AQUIND has increasing levels of exports over the forecast period up to 2038 for Falling Short. The redispatch shows a reduction in exports after 2037. Compared to the original (March 2024) results, exports and imports are very similar.

Figure 79: Annual import and export flows for AQUIND in the MA case for Leading the Way.



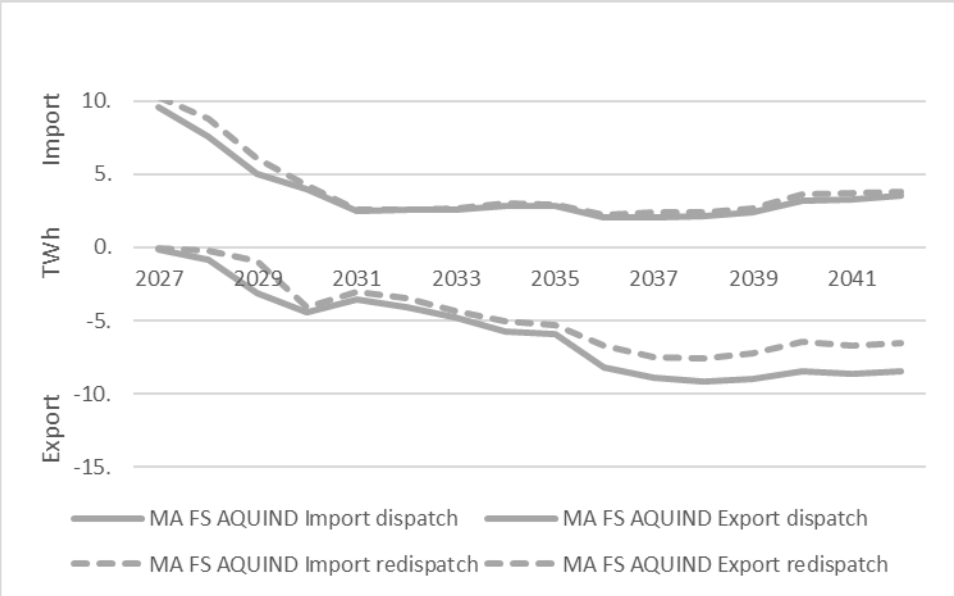
The above figure shows for the dispatch high exports, but lower than in the FA case, and low imports, similar to those in the FA case. The redispatch shows a significant reduction in exports and a slightly increase in imports. Compared to the original (March 2024) results, exports are slightly higher in the dispatch.

Figure 80: Annual import and export flows for AQUIND in the MA case for Consumer Transformation.



The above figure shows high exports, but lower than in the FA case, and low imports in the dispatch. The redispatch shows exports reduced significantly in the early to mid-2030s and a slight increase in imports. Compared to the original (March 2024) results, exports and imports are similar.

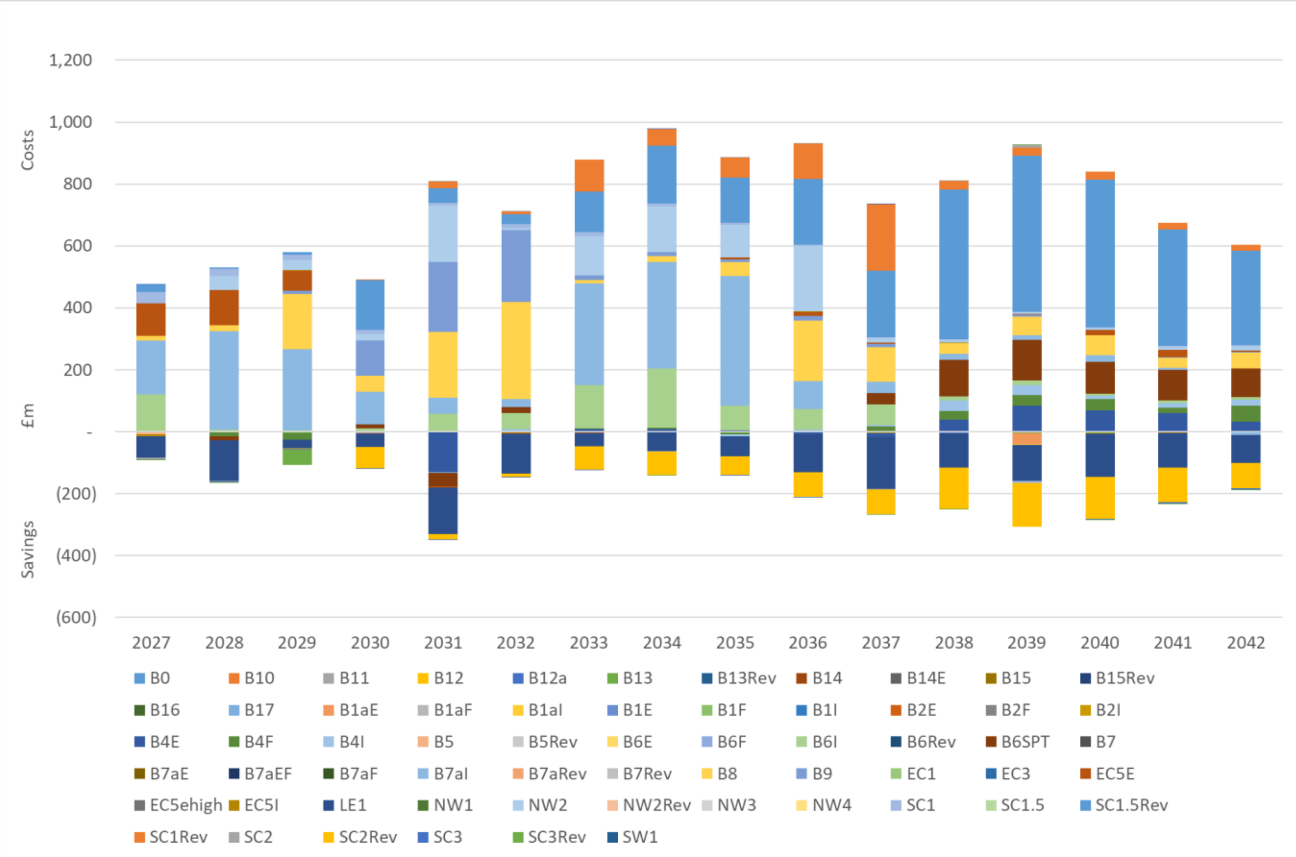
Figure 81: Annual import and export flows for AQUIND in the MA case for Falling Short.



The above figure shows that for the Marginal Additional case, AQUIND has increasing exports, but slightly lower than in the First Additional case, and decreasing imports in the dispatch, which are similar to those in FA. The redispatch shows some reduction in exports, especially in the later years and a very small increase in imports. Compared to the original (March 2024) results, exports and imports are very similar.

Change in constraint costs by boundary

Figure 82: Change in constraint costs by boundary for AQUIND for the First Additional case for Leading the Way.



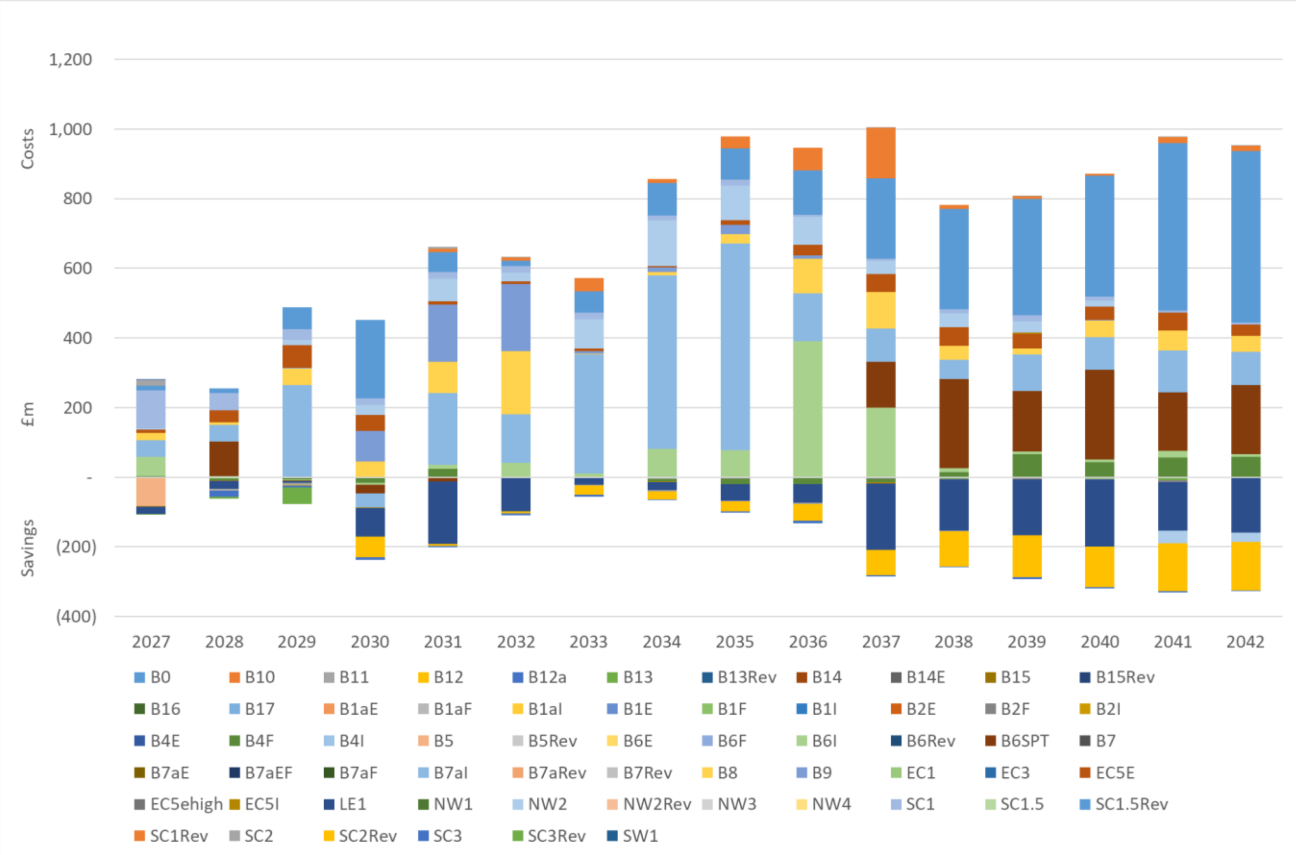
The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for AQUIND for the First Additional case for the Leading the Way scenario. Each different colour represents the change in constraint costs for a particular boundary. It is important to note that the chart shows changes in constraint costs by boundary, i.e. the difference between constraint costs when the project is included and when the project is excluded.

The figure shows that AQUIND increases constraint costs on certain boundaries but also reduces constraint costs on others. Whether the impact is an increase in constraint costs or a reduction in constraint costs for a particular boundary, changes from year to year. The size of change in constraint costs by boundary can also vary significantly from year to year. This is shown clearly in the years 2035 to 2036. The figure also shows that the specific boundaries that have the greatest impact on the total change in constraint costs can vary from year to year. These factors are a result of the changes in demand, supply and network capability over time.

In general, AQUIND increases constraint costs on several northern boundaries, but relieves congestion on certain southern boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis, constraint costs are higher on several northern boundaries

Figure 83: Change in constraint costs by boundary for AQUIND for the First Additional case for Consumer Transformation.

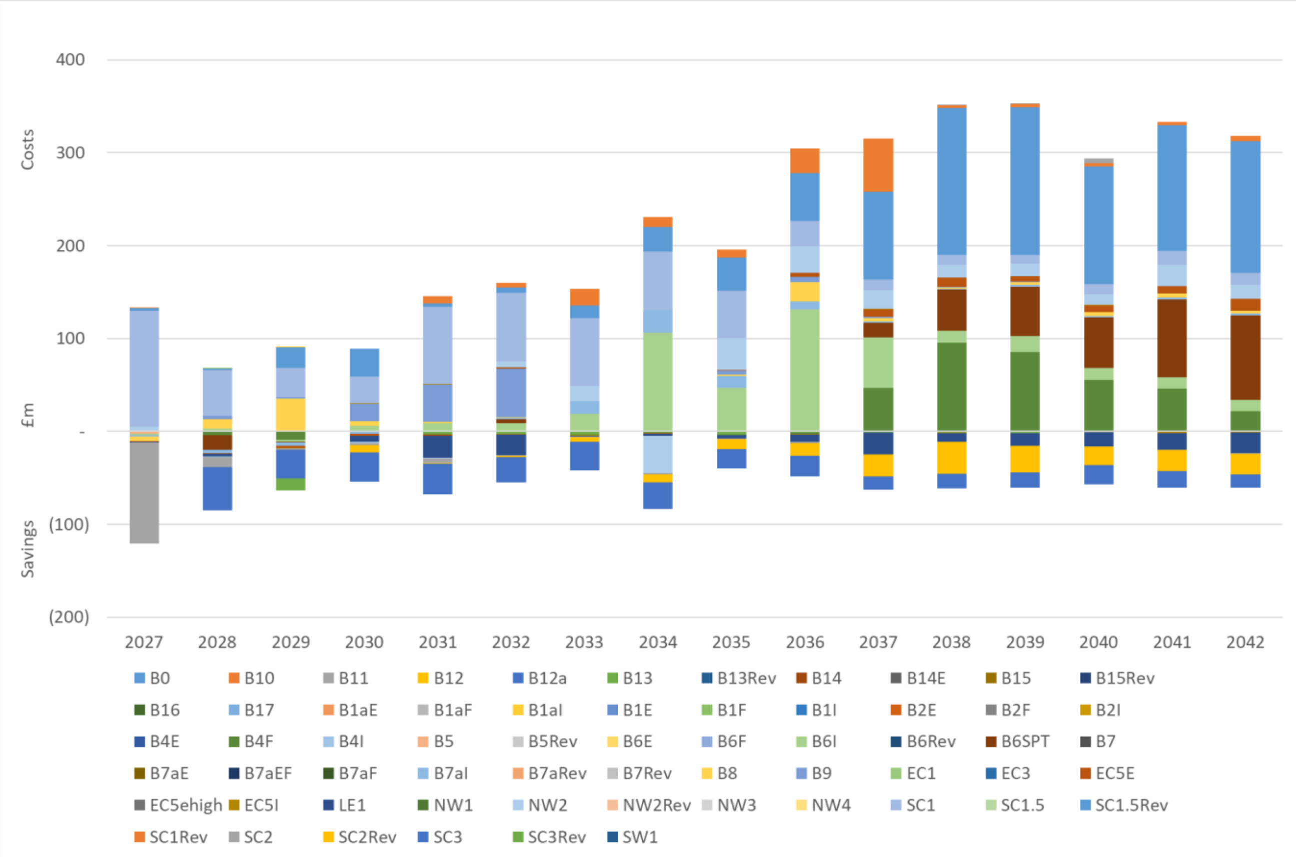


The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for AQUIND for the First Additional case for the Consumer Transformation scenario.

In general, AQUIND increases constraint costs on several northern boundaries, but relieves congestion on certain southern boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis, constraint costs are higher on several northern boundaries.

Figure 84: Change in constraint costs by boundary for AQUIND for the First Additional case for Falling Short.



The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for AQUIND for the First Additional case for the Falling Short scenario.

In general, AQUIND increases constraint costs on several northern boundaries, but relieves congestion on certain southern boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis, constraint costs are slightly higher on several northern boundaries.

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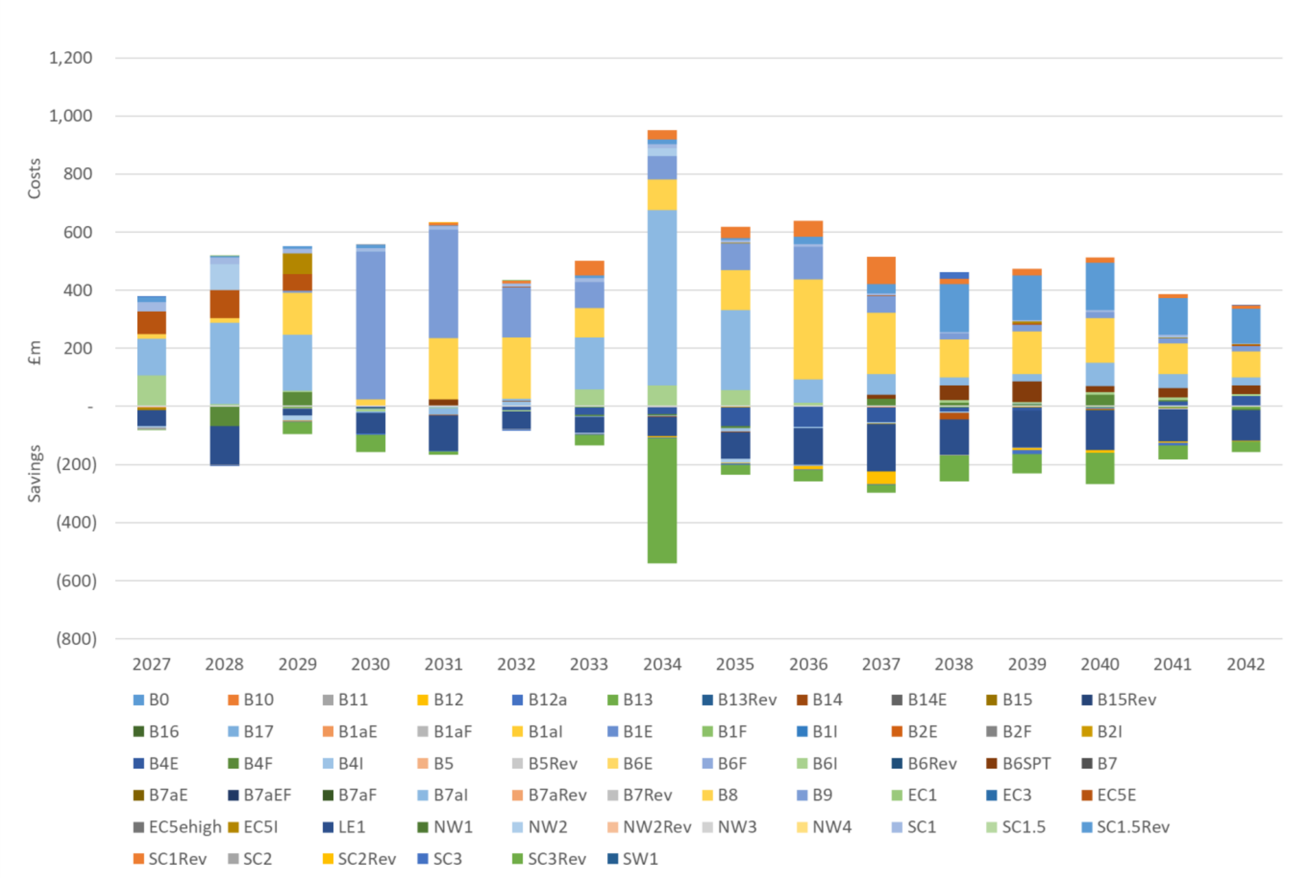
Figure 85: Change in constraint costs by boundary for AQUIND for the Marginal Additional case for Leading the Way.

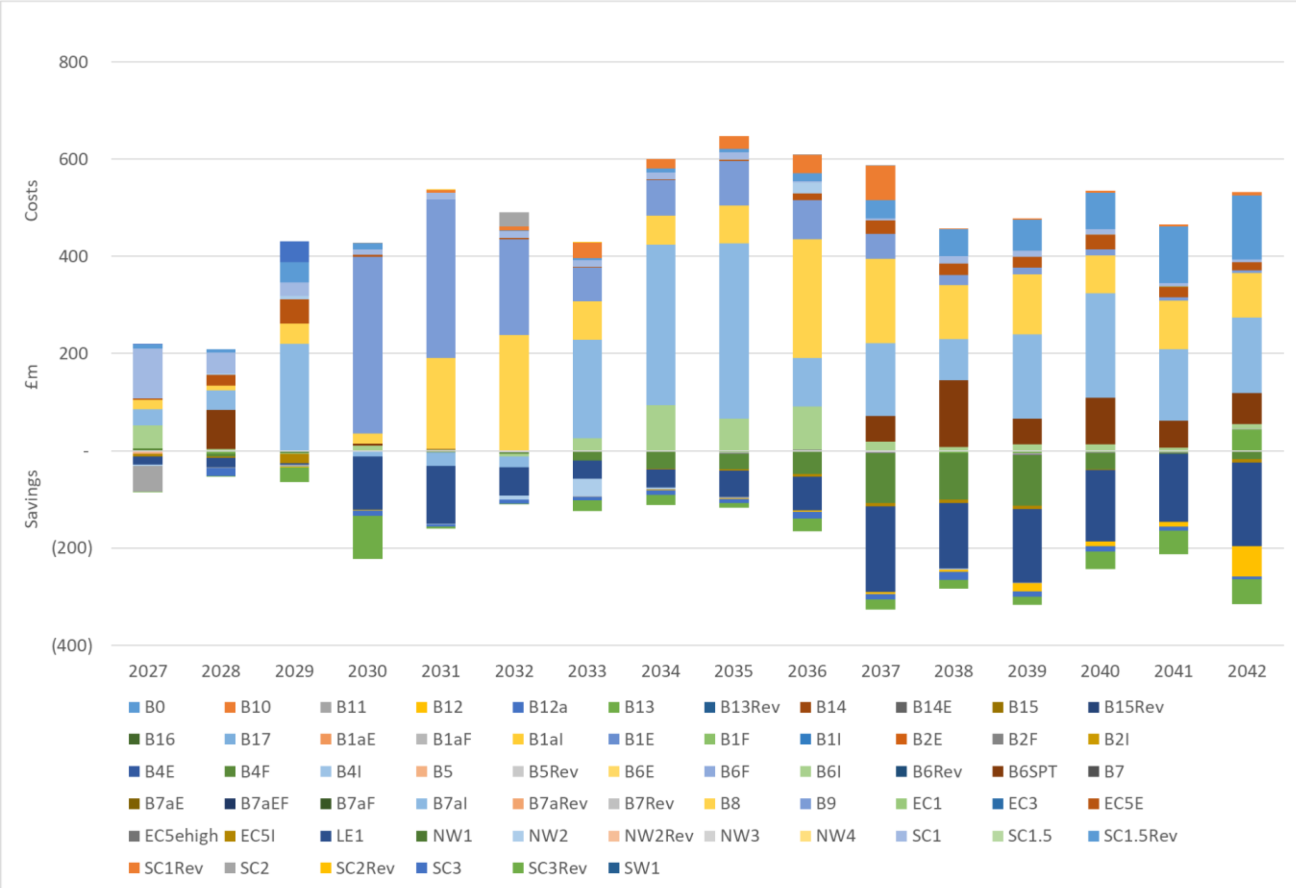


The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for AQUIND for the Marginal Additional case for the Leading the Way scenario.

In general, AQUIND increases constraint costs on several northern boundaries, but relieves congestion on several southern boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis, constraint costs are higher on several northern boundaries.

Figure 86: Change in constraint costs by boundary for AQUIND for the Marginal Additional case for Consumer Transformation.



The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for AQUIND for the Marginal Additional case for the Consumer Transformation scenario.

In general, AQUIND increases constraint costs on several northern boundaries, but relieves congestion on several southern boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis, constraint costs are higher on several northern boundaries.

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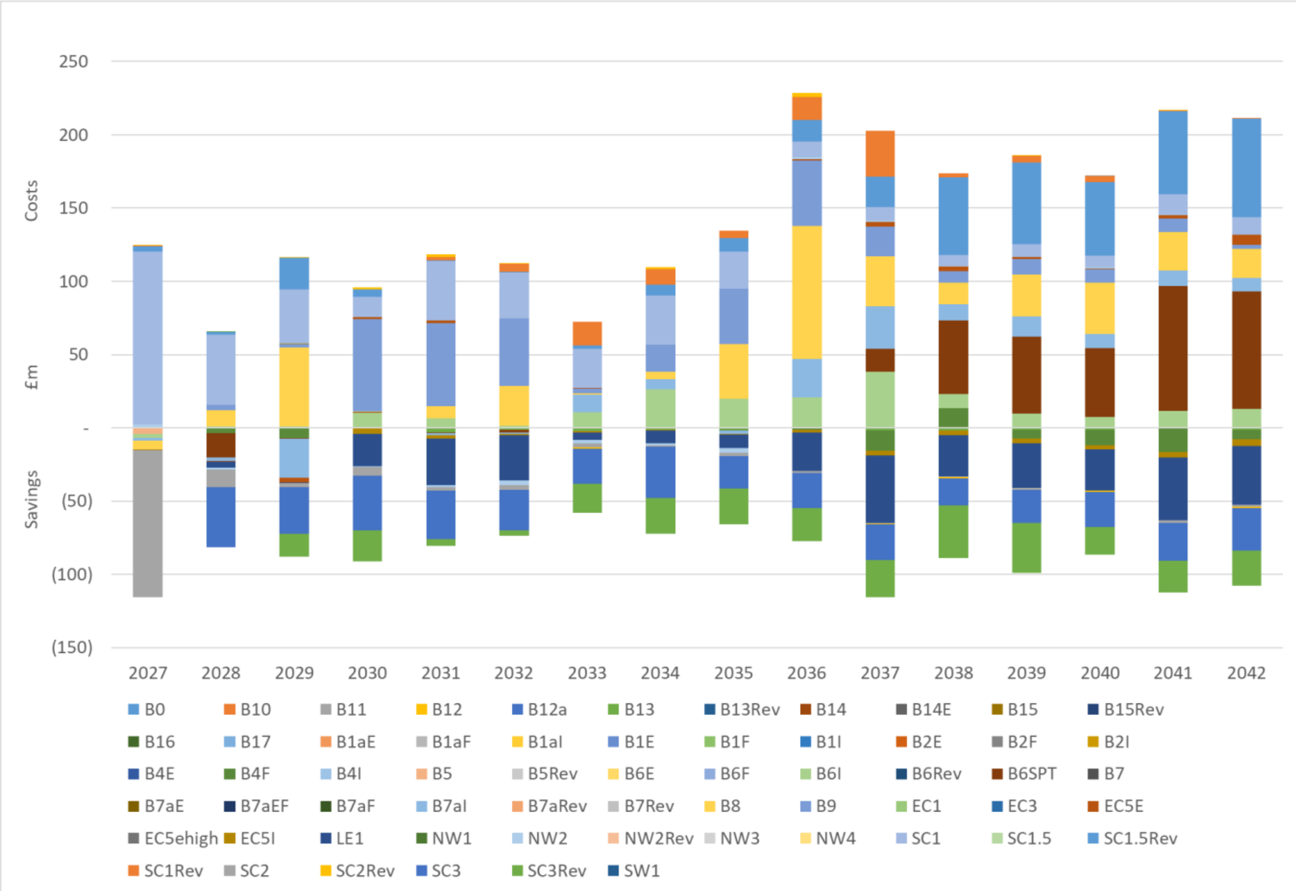
Figure 87: Change in constraint costs by boundary for AQUIND for the Marginal Additional case for Falling Short.



The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for AQUIND for the Marginal Additional case for the Falling Short scenario.

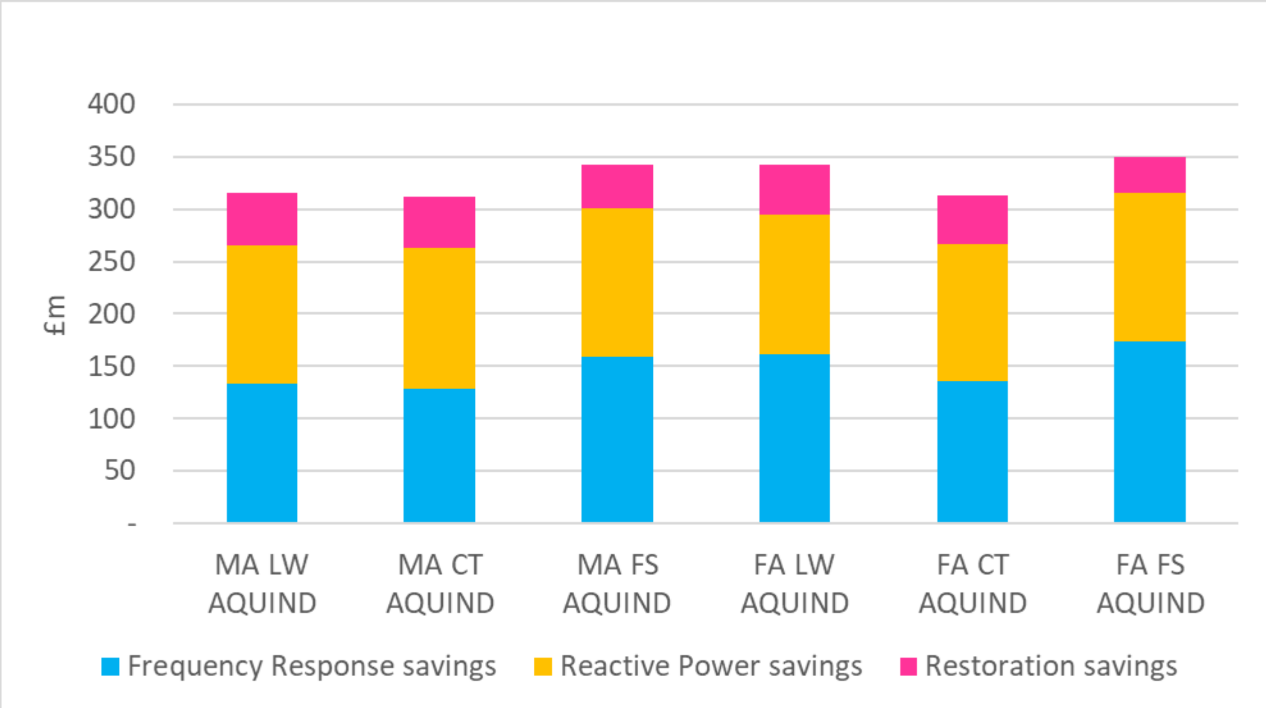
In general, AQUIND increases constraint costs on several northern boundaries, but relieves congestion on certain southern boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis, constraint costs are higher on several northern boundaries.

PV system operation

Note: The modelling and analysis for system operation is the same as that within the March 2024 report. It was not necessary to repeat the work because the change in modelling assumptions would not produce a material change in the results.

Figure 88: PV potential system operability savings for , Present Value 25-year, real 2022, £m.



The above figure shows the potential savings for frequency response, reactive power and restoration services in present value (25-year, 2022 £m) for AQUIND for Leading the Way, Consumer Transformation and Falling Short for both the Marginal Additional and First Additional cases. There is considerable uncertainty around forecasting potential system operability benefits over a 25-year time horizon, but the figure shows that there is potentially significant savings in frequency response, reactive power and restoration services.

There is little variation across the three scenarios and also across the First Additional and Marginal Additional cases. This is because the potential system operability savings from the services provided by AQUIND are less sensitive to flows across the interconnector, whereas the constraint cost impact is highly dependent on the scale and direction of flows across the project.

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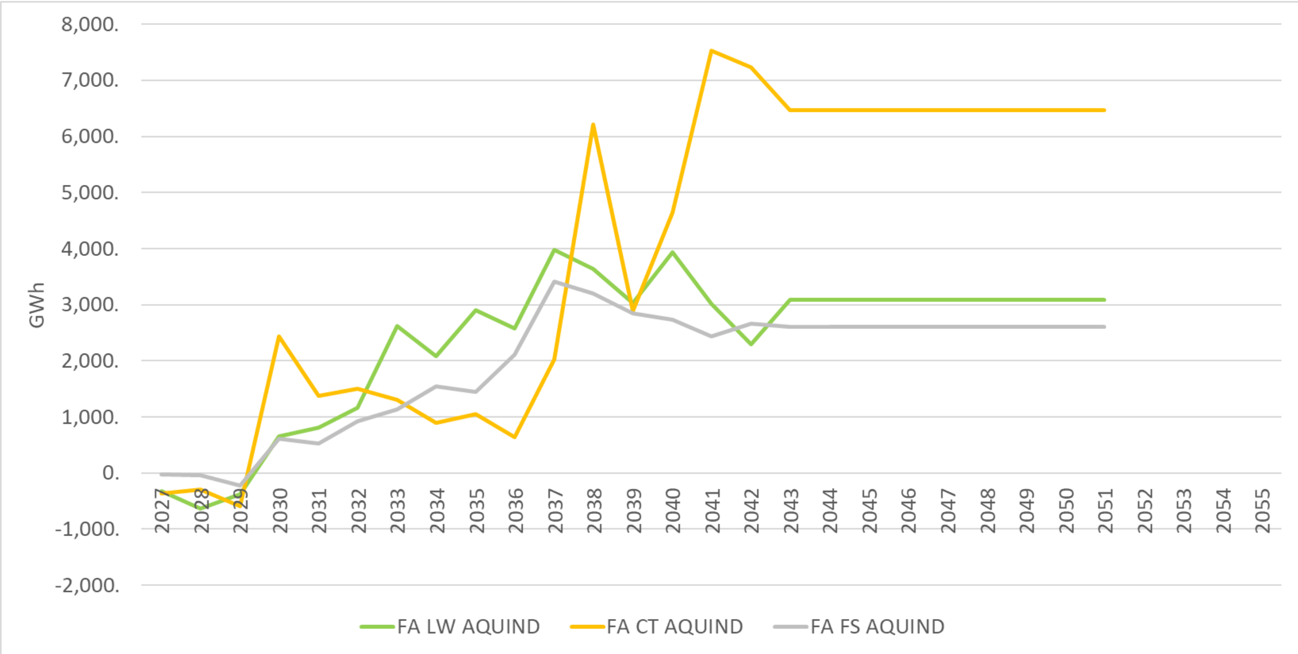
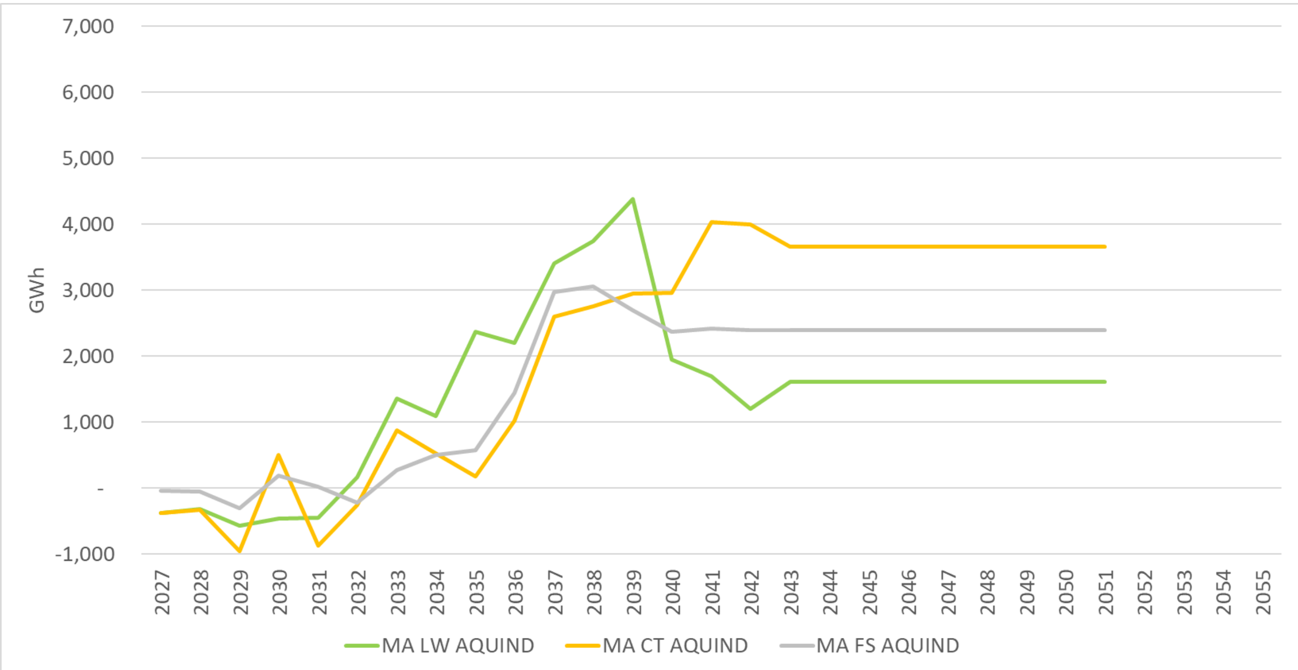
RES curtailment avoided

Figure 89: Annual RES curtailment avoided for AQUIND for the First Additional case.



The above figure shows the renewable energy supply (RES) curtailment avoided on an annual basis for Leading the Way, Consumer Transformation and Falling Short for the First Additional case. Note that beyond 2042, the results are an average of the years 2040, 2041 and 2042, as our detailed modelling with FES22 only extends out to 2042. The figure shows that the level of annual RES curtailment avoided when AQUIND is included is approximately between 1TWh and 6TWh, which equates to approximately between 2.7GWh and 16.4GWh per day.

Figure 90: Annual RES curtailment avoided for AQUIND for the Marginal Additional case.



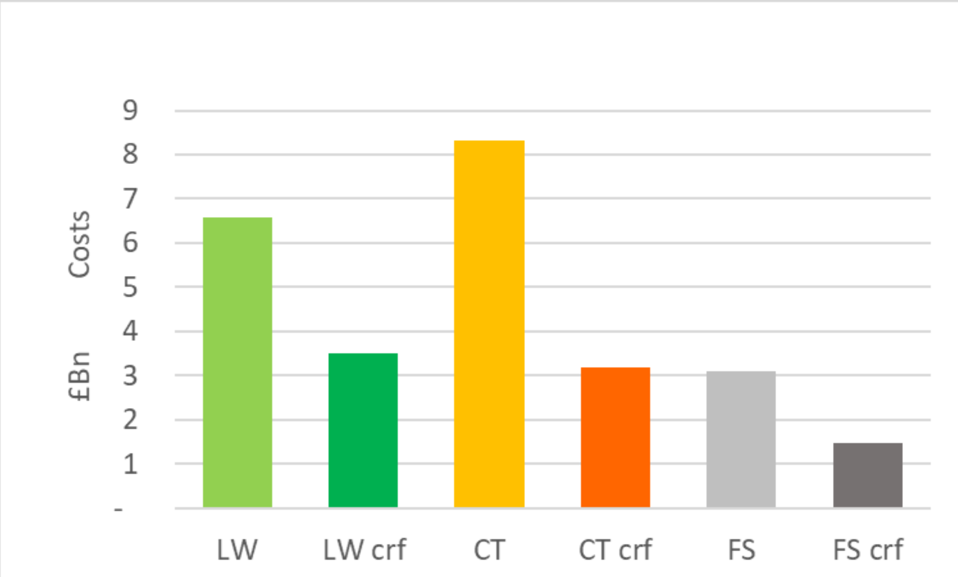
The above figure shows the renewable energy supply (RES) curtailment avoided on an annual basis for Leading the Way, Consumer Transformation and Falling Short for the Marginal Additional case. Note that beyond 2042, the results are an average of the years 2040, 2041 and 2042, as our detailed modelling with FES22 only extends out to 2042. For the years 2027 to 2032 AQUIND often results in a slight increase in RES curtailment in all scenarios: thereafter AQUIND results in RES curtailment avoided of approximately between 0.5TWh and 4TWh, which equates to approximately between 1.4GWh and 11GWh per day.

12. Cronos

Cronos is a W3 interconnector project. It has a capacity of 1.4GW and connects to Belgium.

PV constraint costs

Figure 91: PV additional constraint costs due to Cronos for the First Additional case, Present Value 25-year, real 2022, £m, without and with Constraint Reduction Factor applied.



The above figure shows the additional constraint costs with the inclusion of Cronos for the FA case. Without the Constraint Reduction Factor applied, in the Leading the Way scenario (LW) constraint costs are increased by £6.6bn, in Consumer Transformation (CT) by £8.3bn and in the Falling Short (FS) scenario by £3.1bn.

With the Constraint Reduction Factor applied, in the Leading the Way scenario (LW) constraint costs are increased by £3.5n, in Consumer Transformation (CT) by £3.2bn and in the Falling Short (FS) scenario by £1.5bn.

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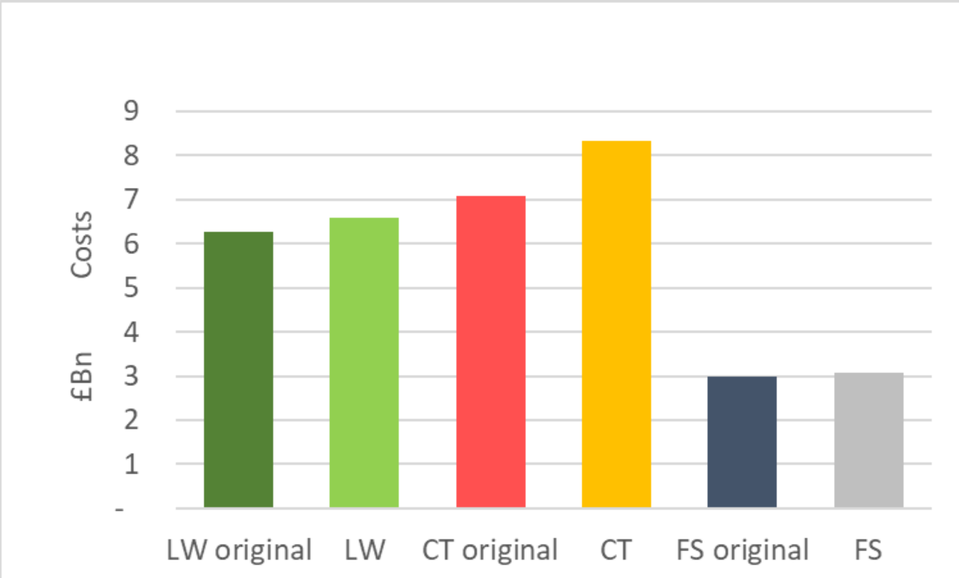
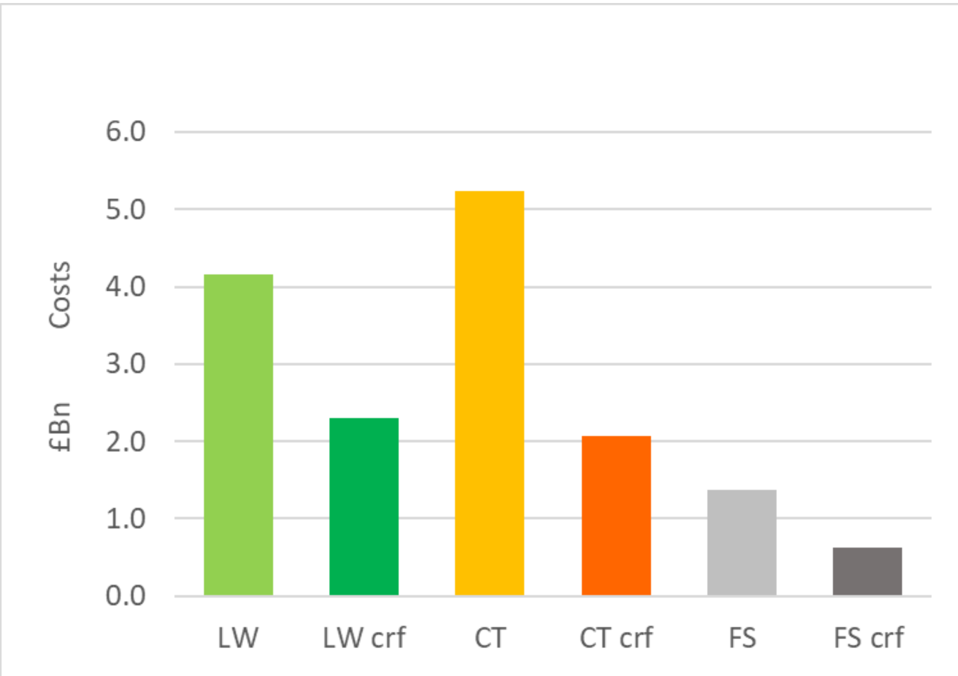
Figure 92: PV additional constraint costs due to Cronos for the First Additional case, Present Value 25-year, real 2022, £m, for the original analysis (March 2024) and for Nautilus at Grain with 1.4GW link and Irish demand and generation from TYNDP.



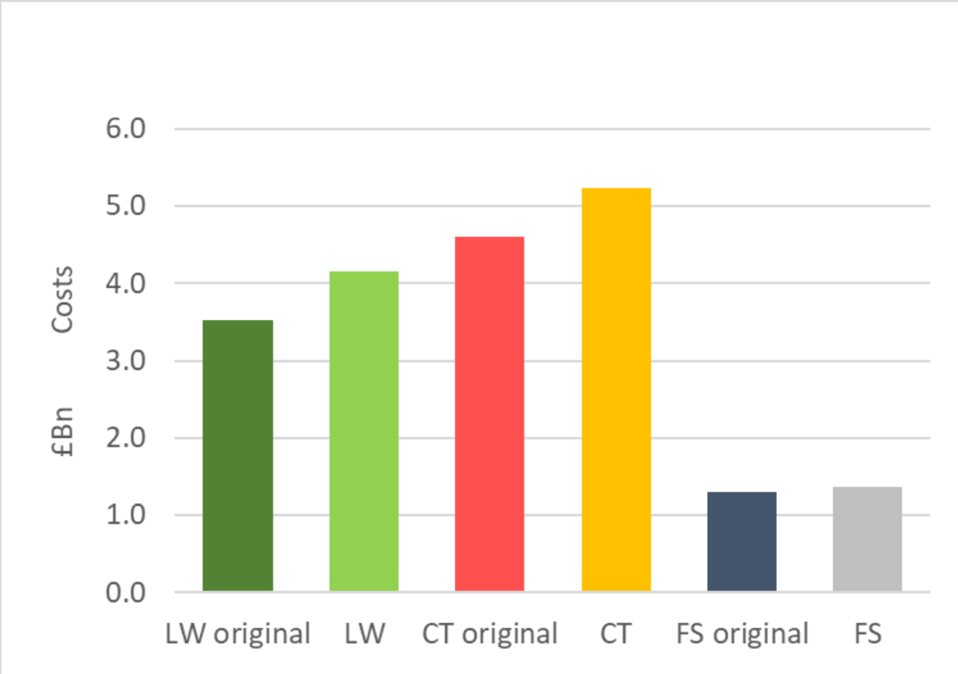
The above figure shows that the changes made to the scenarios, that is the reduction in the capacity of the link connecting the Nautilus offshore platform to Belgium from 3.5GW to 1.4GW and the change in Irish demand and generation to reflect final TYNDP data results in an increase in constraint costs in all three scenarios, with the highest increase in CT.

Figure 93: PV additional constraint costs due to Cronos for the Marginal Additional case, Present Value 25-year, real 2022, £m, without and with Constraint Reduction Factor applied.



The above figure shows the additional constraint costs with the inclusion of Cronos for the MA case. Without the Constraint Reduction Factor applied, in the Leading the Way scenario (LW) constraint costs are increased by £4.2bn, in Consumer Transformation (CT) by £5.2bn and in the Falling Short (FS) scenario by £1.4bn. With the Constraint Reduction Factor applied, in the Leading the Way scenario (LW) constraint costs are increased by £2.3bn, in Consumer Transformation (CT) by £2.1bn and in the Falling Short (FS) scenario by £0.6bn.

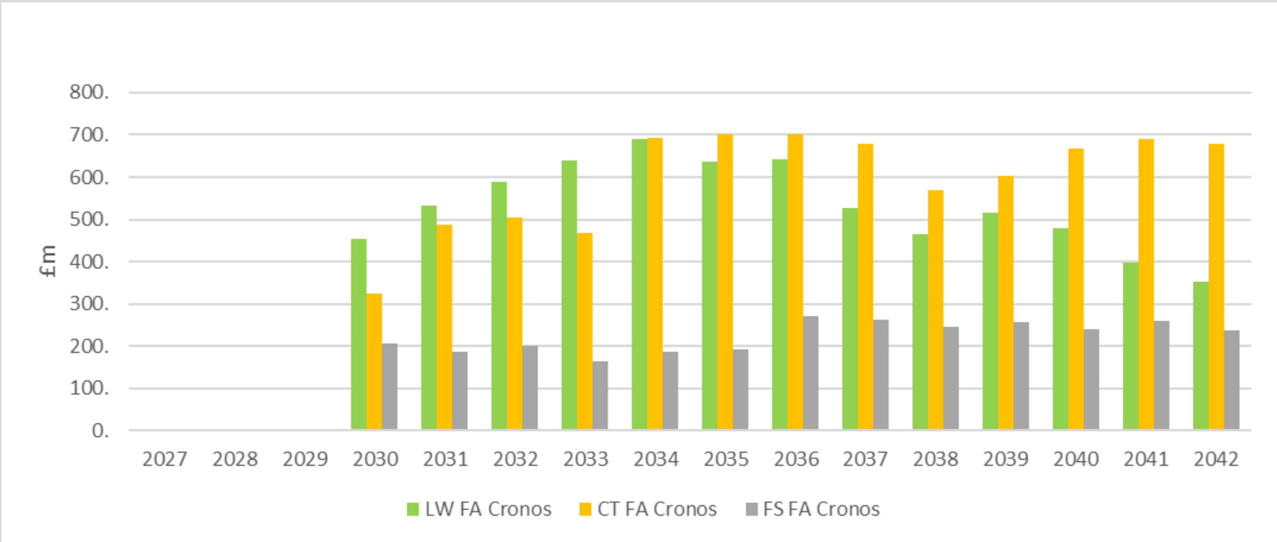
Figure 94: PV additional constraint costs due to Cronos for the Marginal Additional case, Present Value 25-year, real 2022, £m, for the original analysis (March 2024) and for Nautilus at Grain with 1.4GW link and Irish demand and generation from TYNDP.



The above figure shows that the changes made to the scenarios, that is the reduction in the capacity of the link connecting the Nautilus offshore platform to Belgium from 3.5GW to 1.4GW and the change in Irish demand and generation to reflect final TYNDP data results in an increase in constraint costs in all three scenarios, but with the largest increases in LW and CT.

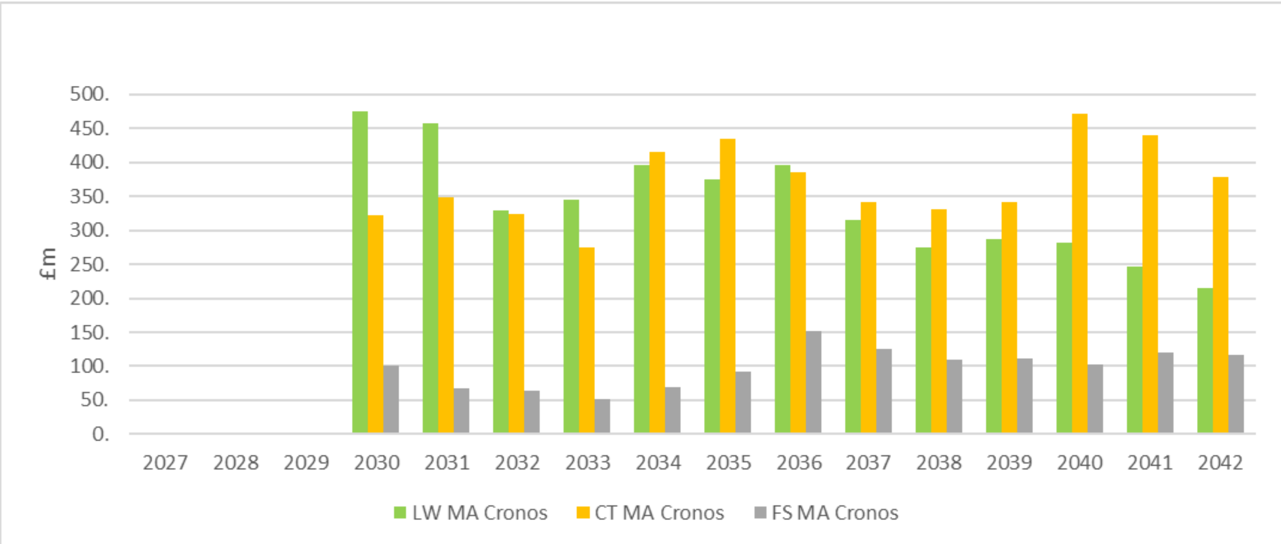
Annual constraint costs (undiscounted)

Figure 95: Additional annual constraint costs (undiscounted) due to Cronos for the First Additional case.



The above figure shows that Cronos results in an increase in constraint costs of approximately £400m to £600m (undiscounted) in CT and LW for the years 2031 to 2042. In FS constraint cost increases are much lower, in the range £150m to £250. The results are higher than the original (March 2024) results for LW and CT.

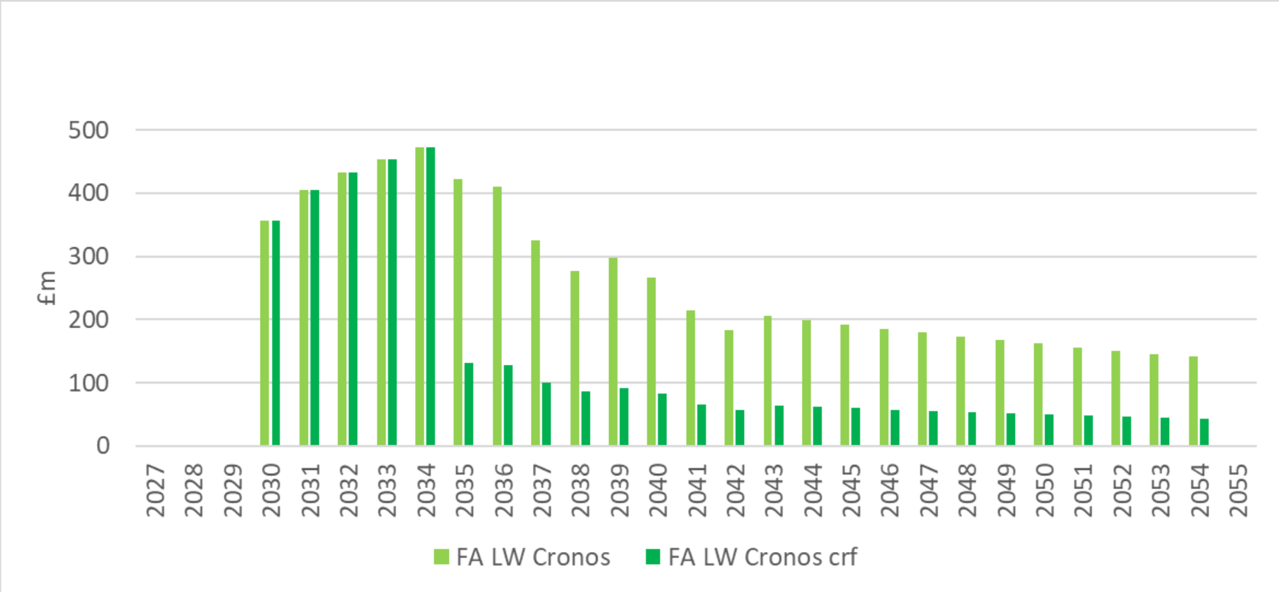
Figure 96: Additional annual constraint costs (undiscounted) due to Cronos for the Marginal Additional case.



In the Marginal Additional case, Cronos results in an increase in constraint costs of approximately £250m to £400m (undiscounted) in CT and LW for the years 2030 to 2040. FS shows lower levels of additional constraint costs compared to LW and CT, in the range of £50m to £150m. The results are higher than the original (March 2024) results for LW and CT.

Annual constraint costs (discounted), without and with Constraint Reduction Factor

Figure 97: Additional annual constraint costs (discounted) due to Cronos for the First Additional case for Leading the Way, without and with Constraint Reduction Factor applied.



The above chart shows the additional constraint costs without and with the Constraint Reduction Factor (CRF) applied for the Leading the Way scenario for the First Additional case. The chart shows the impact of the CRF being applied from 2035 onwards.

Figure 98: Additional annual constraint costs (discounted) due to Cronos for the First Additional case for Consumer Transformation, without and with Constraint Reduction Factor applied.

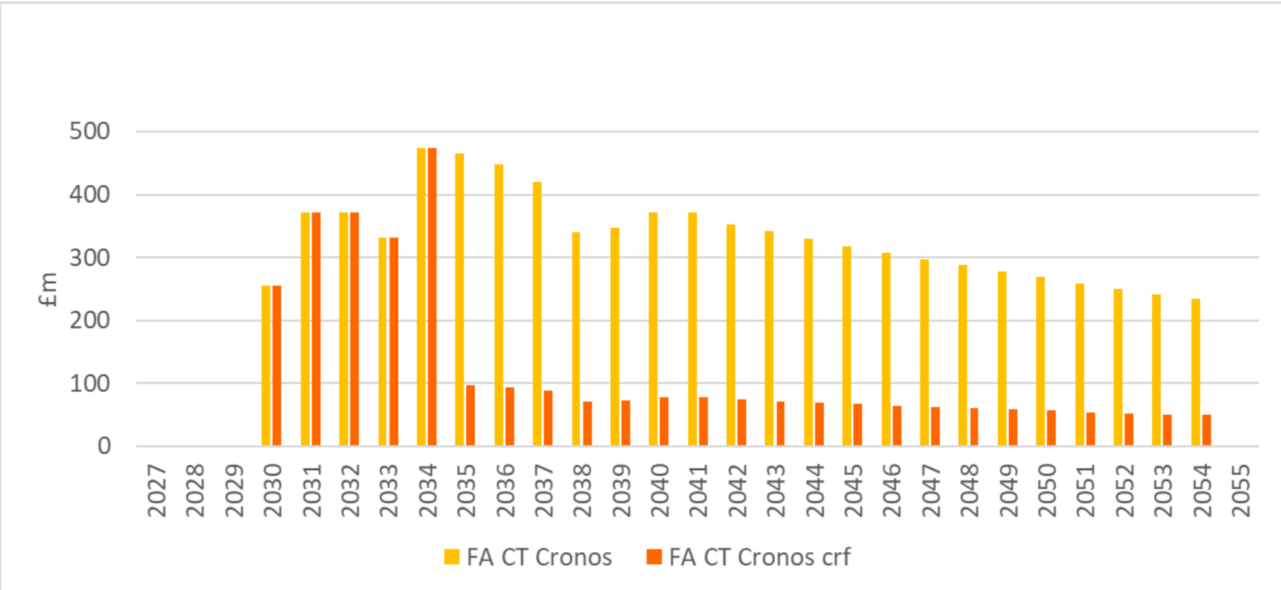
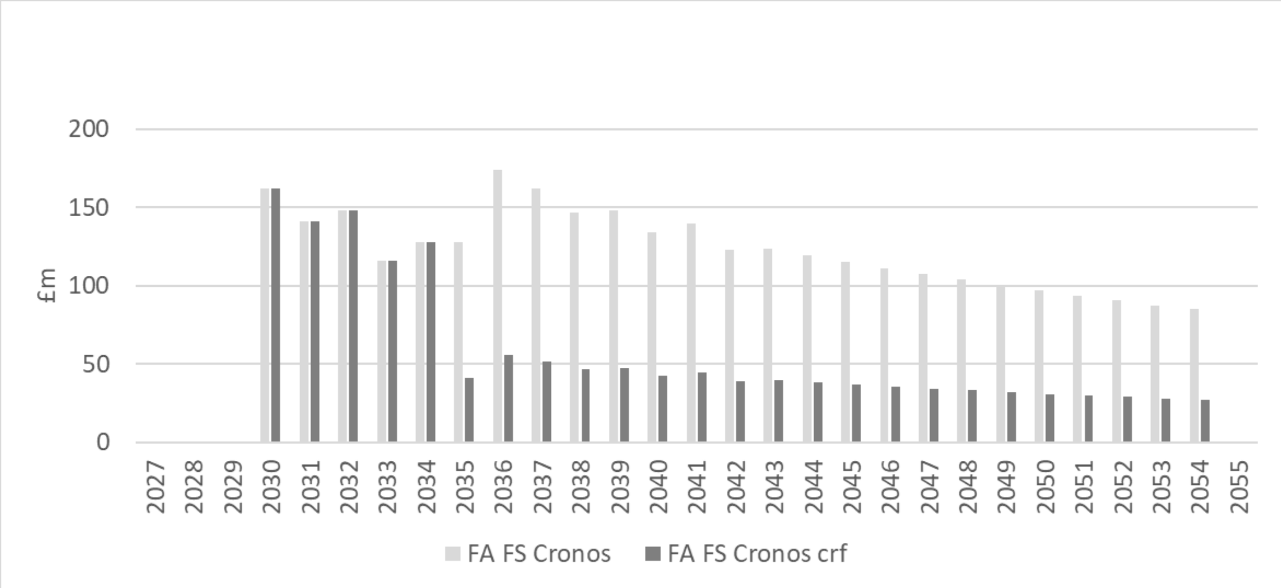
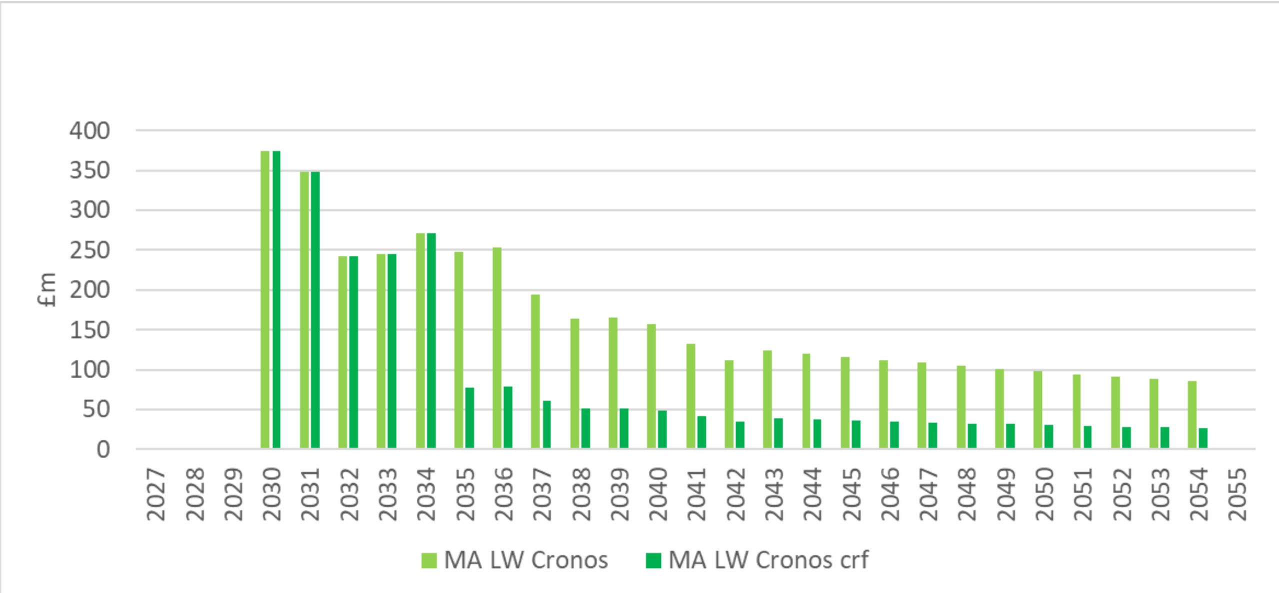


Figure 99: Additional annual constraint costs (discounted) due to Cronos for the First Additional case for Falling Short, without and with Constraint Reduction Factor applied.



The above chart shows the additional constraint costs without and with the Constraint Reduction Factor (CRF) applied. The chart shows the impact of the CRF being applied from 2035 onwards.

Figure 100: Additional annual constraint costs (discounted) due to Cronos for the Marginal Additional case for Leading the Way, without and with Constraint Reduction Factor applied.



The above chart shows the additional constraint costs without and with the Constraint Reduction Factor (CRF) applied for the Leading the Way scenario for the Marginal Additional case. The chart shows the impact of the CRF being applied from 2035 onwards.

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Figure 101: Additional annual constraint costs (discounted) due to Cronos for the Marginal Additional case for Consumer Transformation, without and with Constraint Reduction Factor applied.

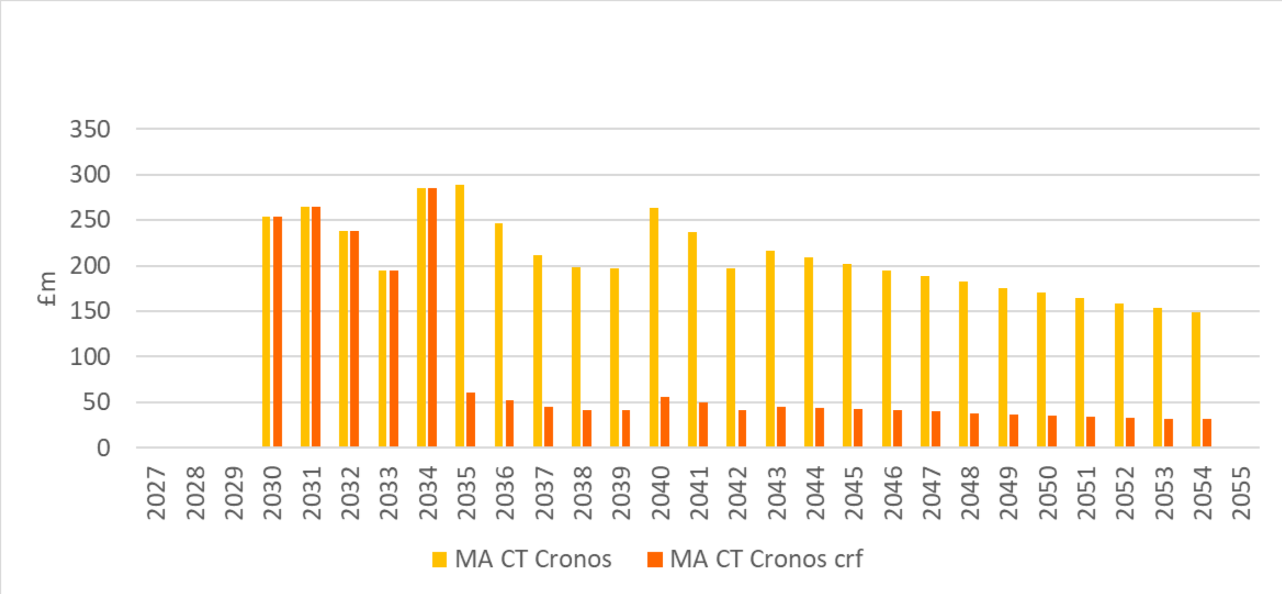
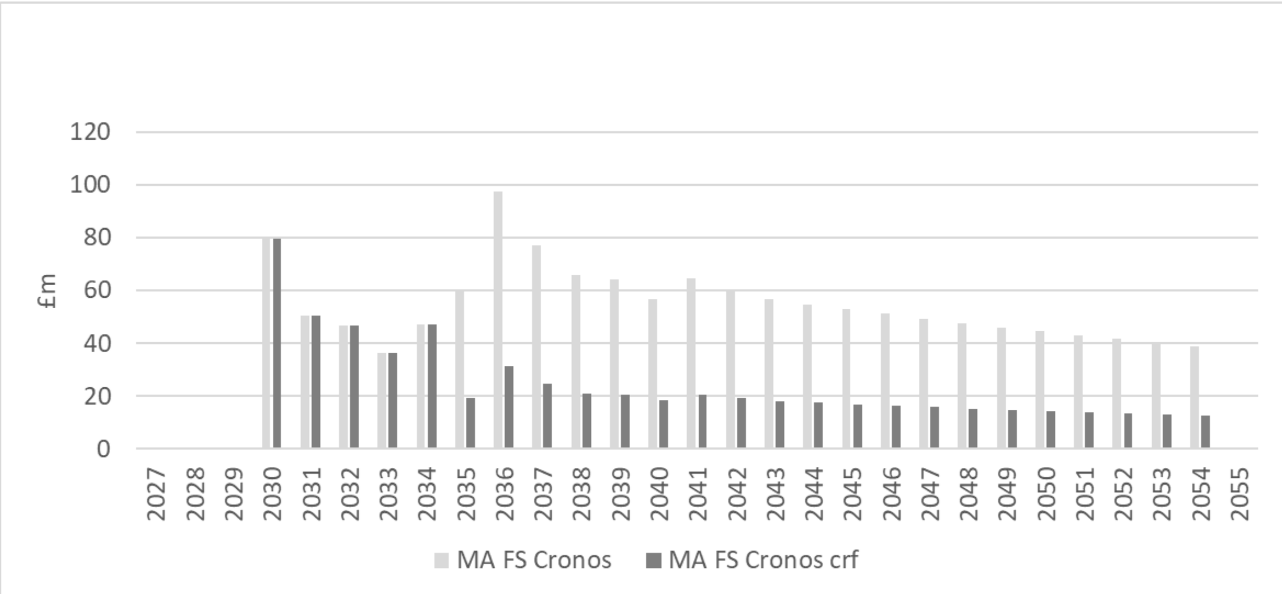
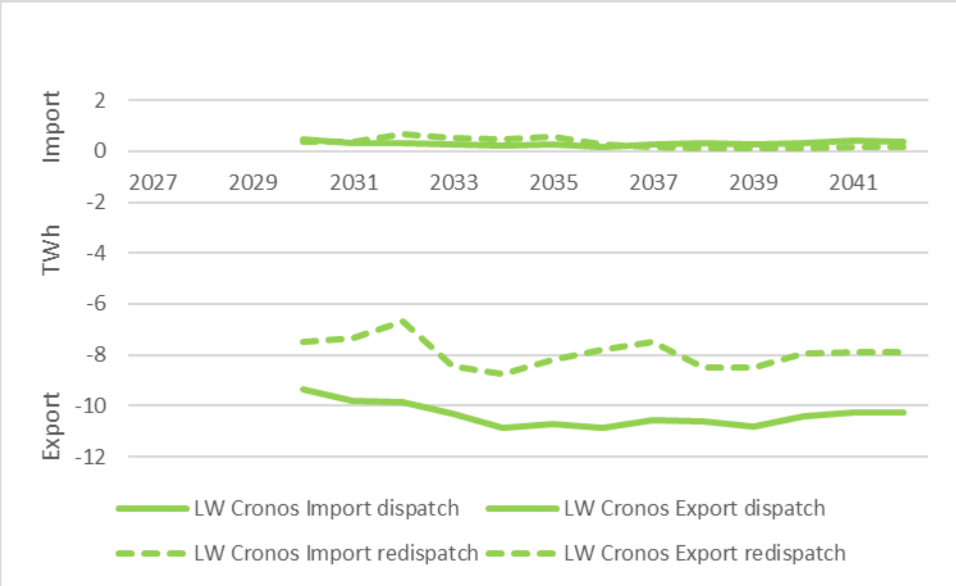


Figure 102: Additional annual constraint costs (discounted) due to Cronos for the Marginal Additional case for Falling Short, without and with Constraint Reduction Factor applied.



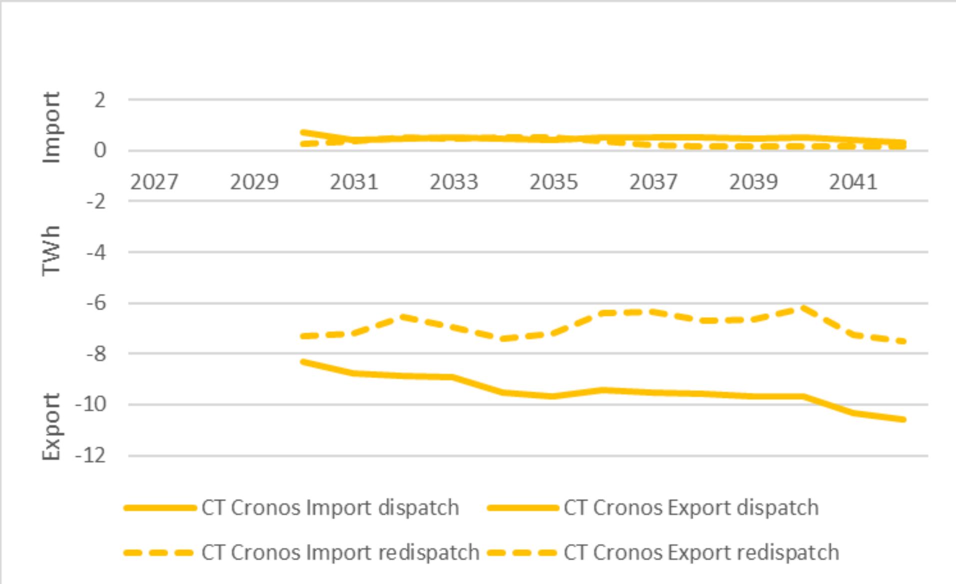
Annual import and export flows for dispatch and redispatch

Figure 103: Annual import and export flows for Cronos in the FA case for Leading the Way.



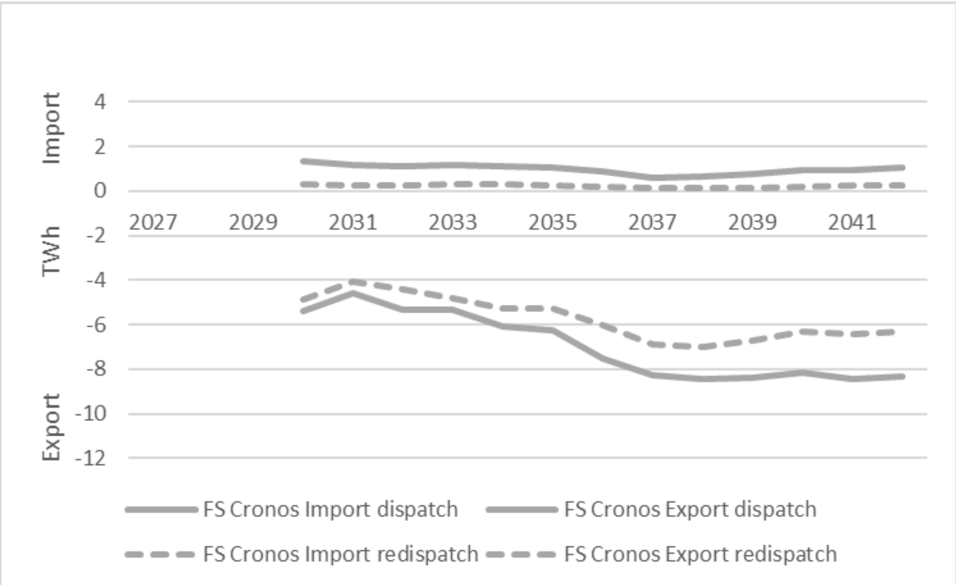
The above figure shows high exports and very low imports in the dispatch. The redispatch shows a significant reduction in exports and a very slight change in imports. Compared to the original (March 2024) results, exports are slightly higher.

Figure 104: Annual import and export flows for Cronos in the FA case for Consumer Transformation.



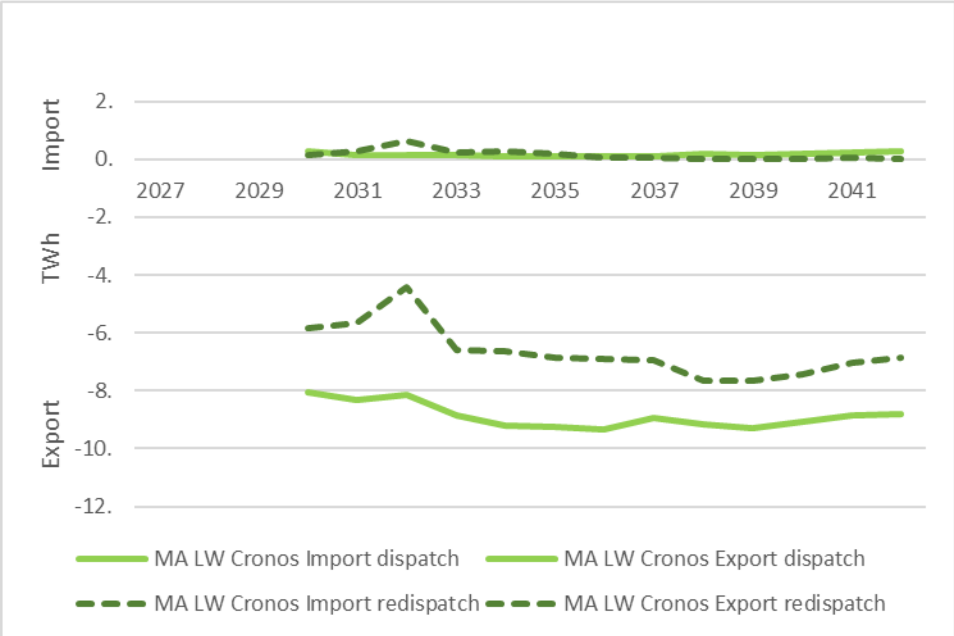
The above figure shows high exports and very low imports in the dispatch. The redispatch shows a significant reduction in exports and only minor changes in imports. Compared to the original (March 2024) results, the results are very similar.

Figure 105: Annual import and export flows for Cronos in the FA case for Falling Short.



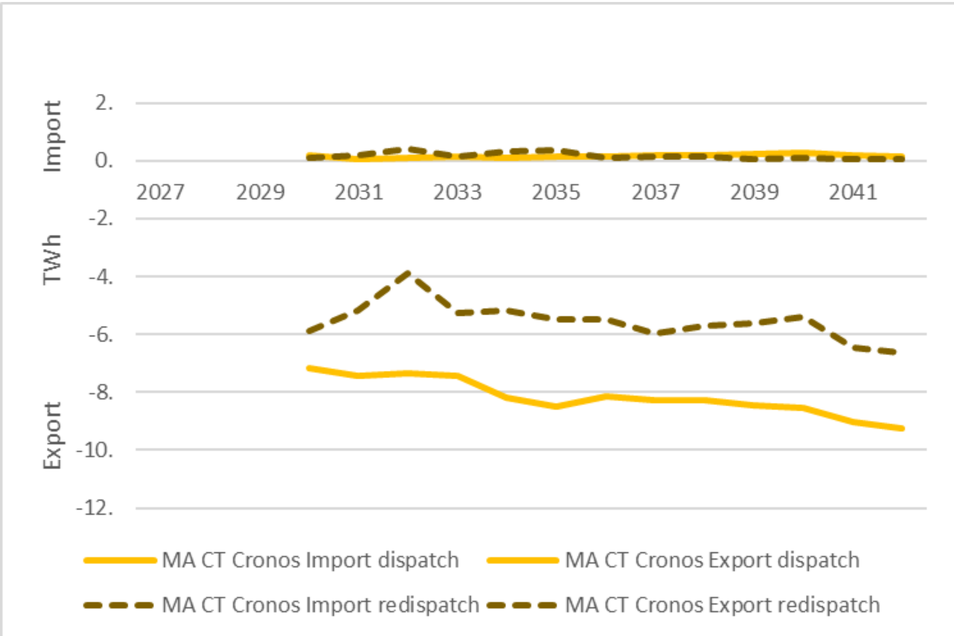
The above figure shows that for the First Additional case Cronos has increasing levels of exports over the forecast period up to 2038 for Falling Short. The redispatch shows a reduction in exports and a significant reduction in imports. Compared to the original (March 2024) results, the results are very similar.

Figure 106: Annual import and export flows for Cronos in the MA case for Leading the Way.



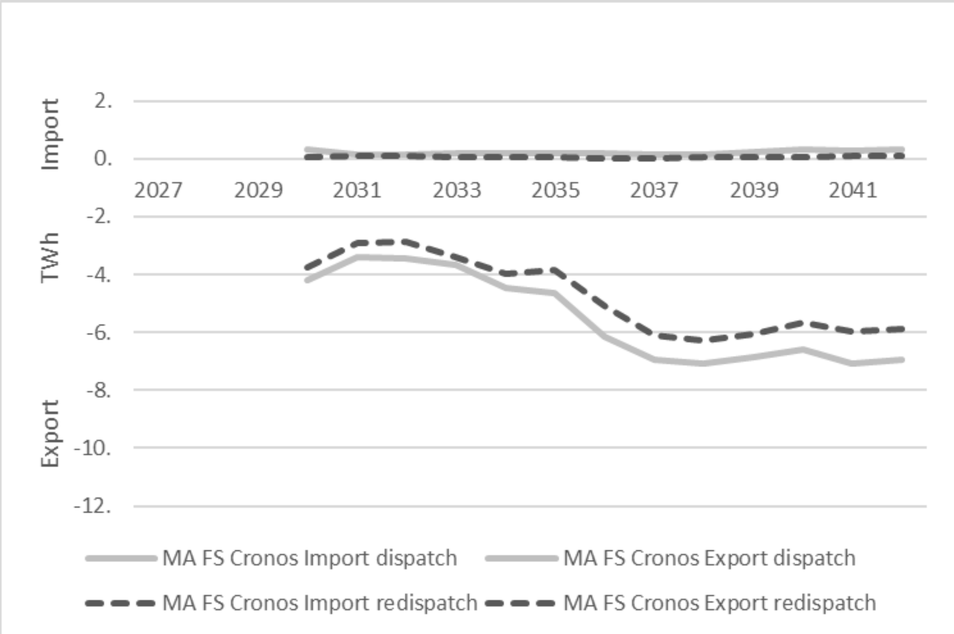
The above figure shows for the dispatch high exports, but lower than in the FA case, and very low imports that are similar to those in the FA case. The redispatch shows a significant reduction in exports and little change in imports. Compared to the original (March 2024) results, exports are slightly higher and imports are similar.

Figure 107: Annual import and export flows for Cronos in the MA case for Consumer Transformation.



The above figure shows high exports, but lower than in the FA case, and very low imports in the dispatch. The redispatch shows exports reduced significantly for all the years and little change in imports. Compared to the original (March 2024) results, exports are slightly higher and imports are very similar.

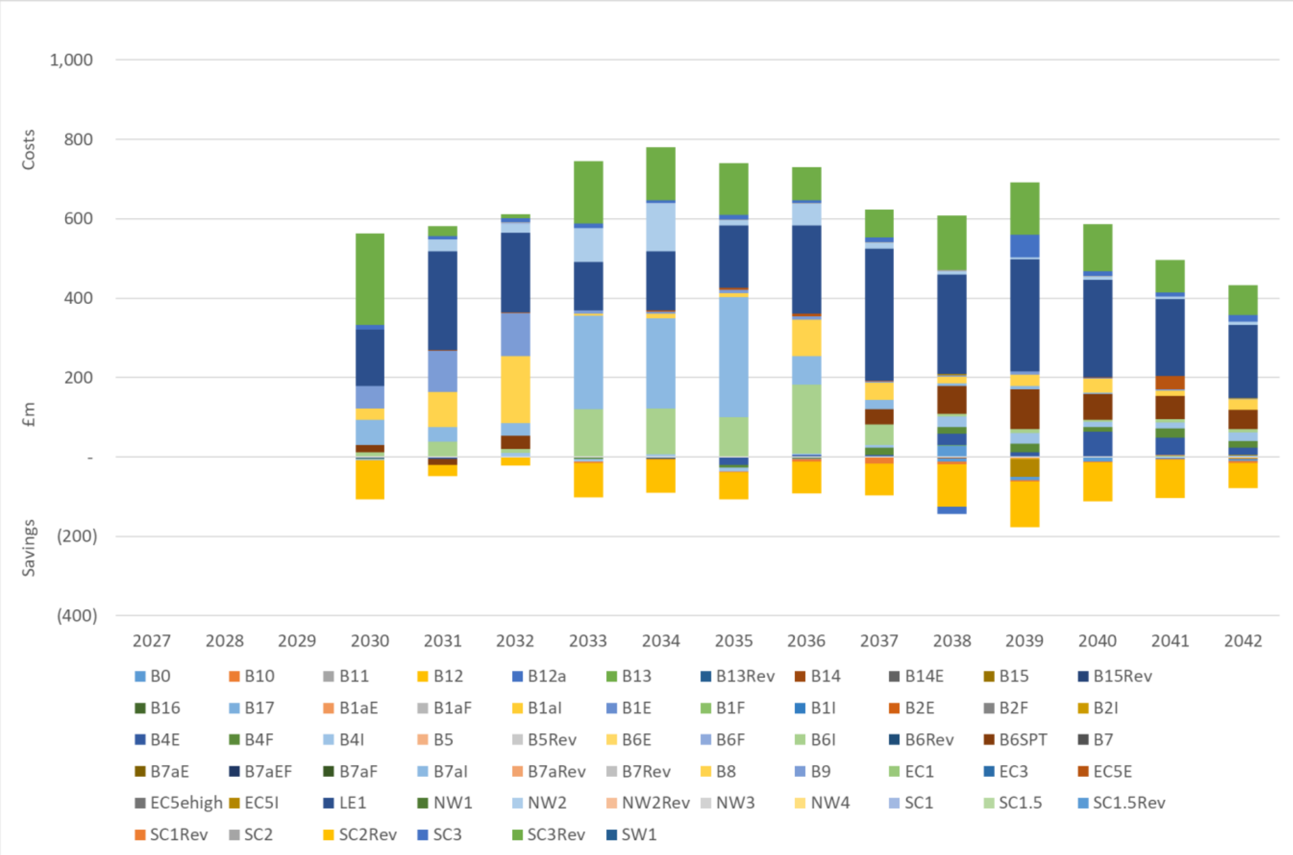
Figure 108: Annual import and export flows for Cronos in the MA case for Falling Short.



The above figure shows that for the Marginal Additional case, Cronos has increasing exports, but lower than in the First Additional case, and minimal imports in the dispatch, which are lower than those in FA. The redispatch shows some reduction in exports, especially in the later years and a further reduction in the very low imports. Compared to the original (March 2024) results, exports are lower and imports are very similar.

Change in constraint costs by boundary

Figure 109: Change in constraint costs by boundary for Cronos for the First Additional case for Leading the Way.



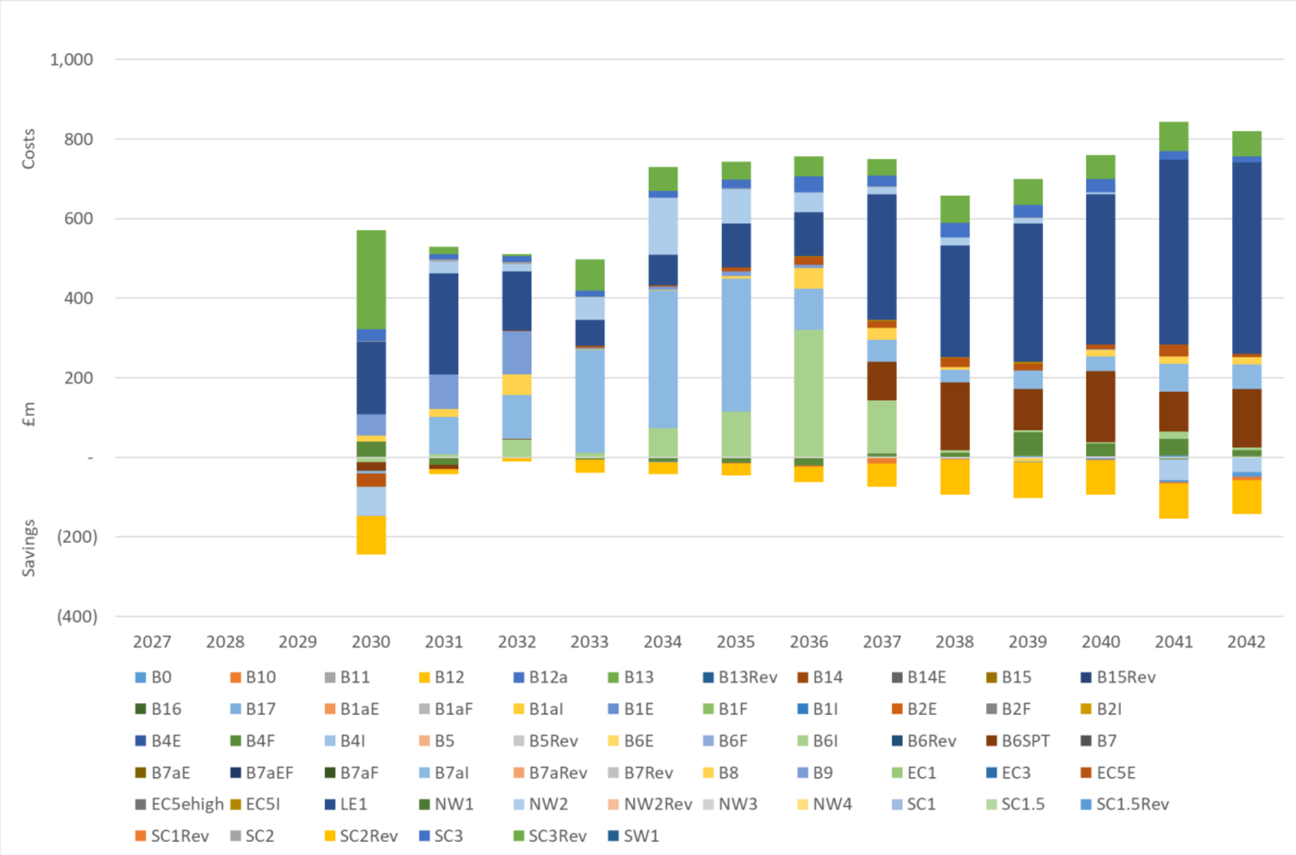
The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for Cronos for the First Additional case for the Leading the Way scenario. Each different colour represents the change in constraint costs for a particular boundary. It is important to note that the chart shows changes in constraint costs by boundary, i.e. the difference between constraint costs when the project is included and when the project is excluded.

The figure shows that Cronos increases constraint costs on certain boundaries but also reduces constraint costs on others. Whether the impact is an increase in constraint costs or a reduction in constraint costs for a particular boundary, changes from year to year. The size of change in constraint costs by boundary can also vary significantly from year to year. This is shown clearly in the years 2036 to 2037. The figure also shows that the specific boundaries that have the greatest impact on the total change in constraint costs can vary from year to year. These factors are a result of the changes in demand, supply and network capability over time.

In general, Cronos increases constraint costs on several northern and southern boundaries but relieves congestion on another southern boundary. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis, constraint costs are higher on several northern and southern boundaries.

Figure 110: Change in constraint costs by boundary for Cronos for the First Additional case for Consumer Transformation.

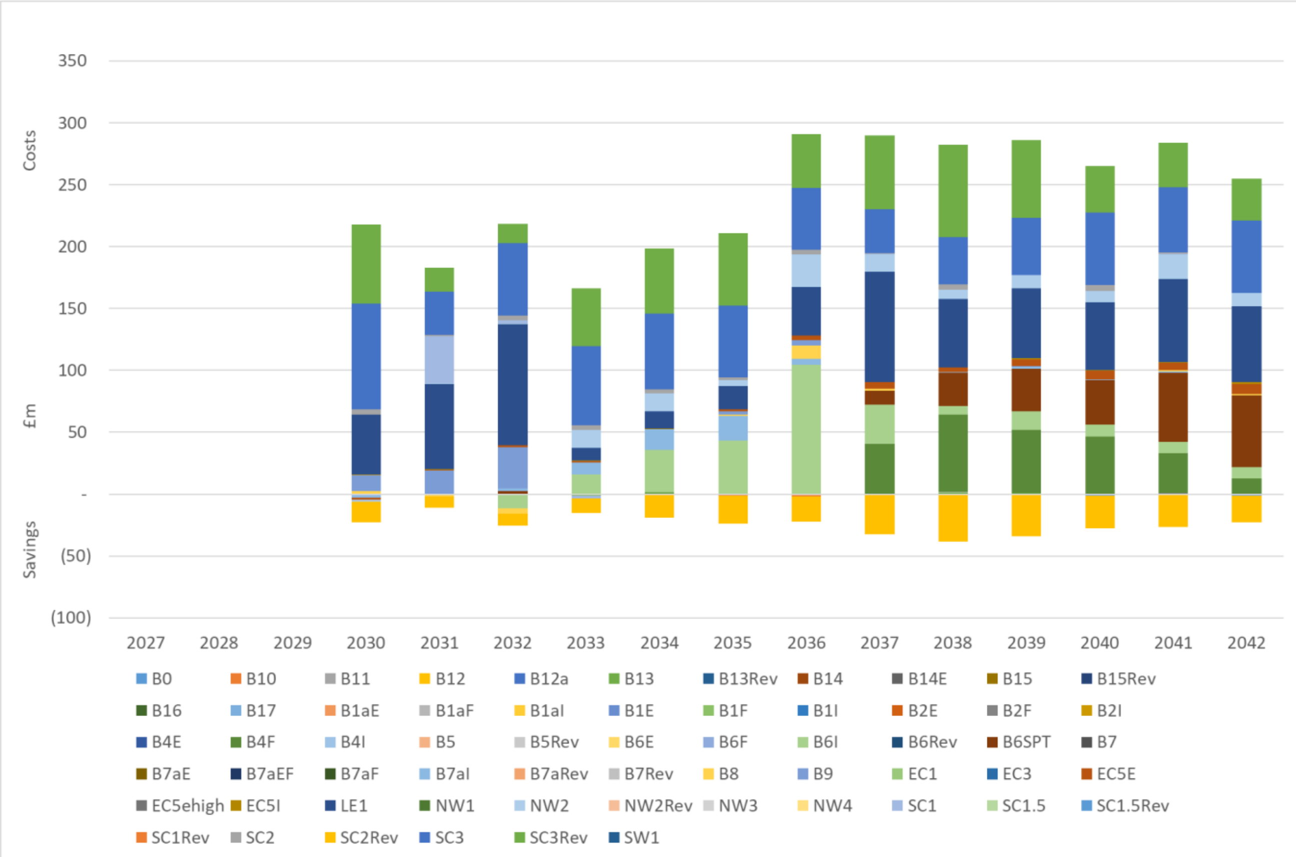


The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for Cronos for the First Additional case for the Consumer Transformation scenario.

In general, Cronos increases constraint costs on several northern and southern boundaries but relieves congestion on another southern boundary. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis, constraint costs are higher on several northern boundaries.

Figure 111: Change in constraint costs by boundary for Cronos for the First Additional case for Falling Short.

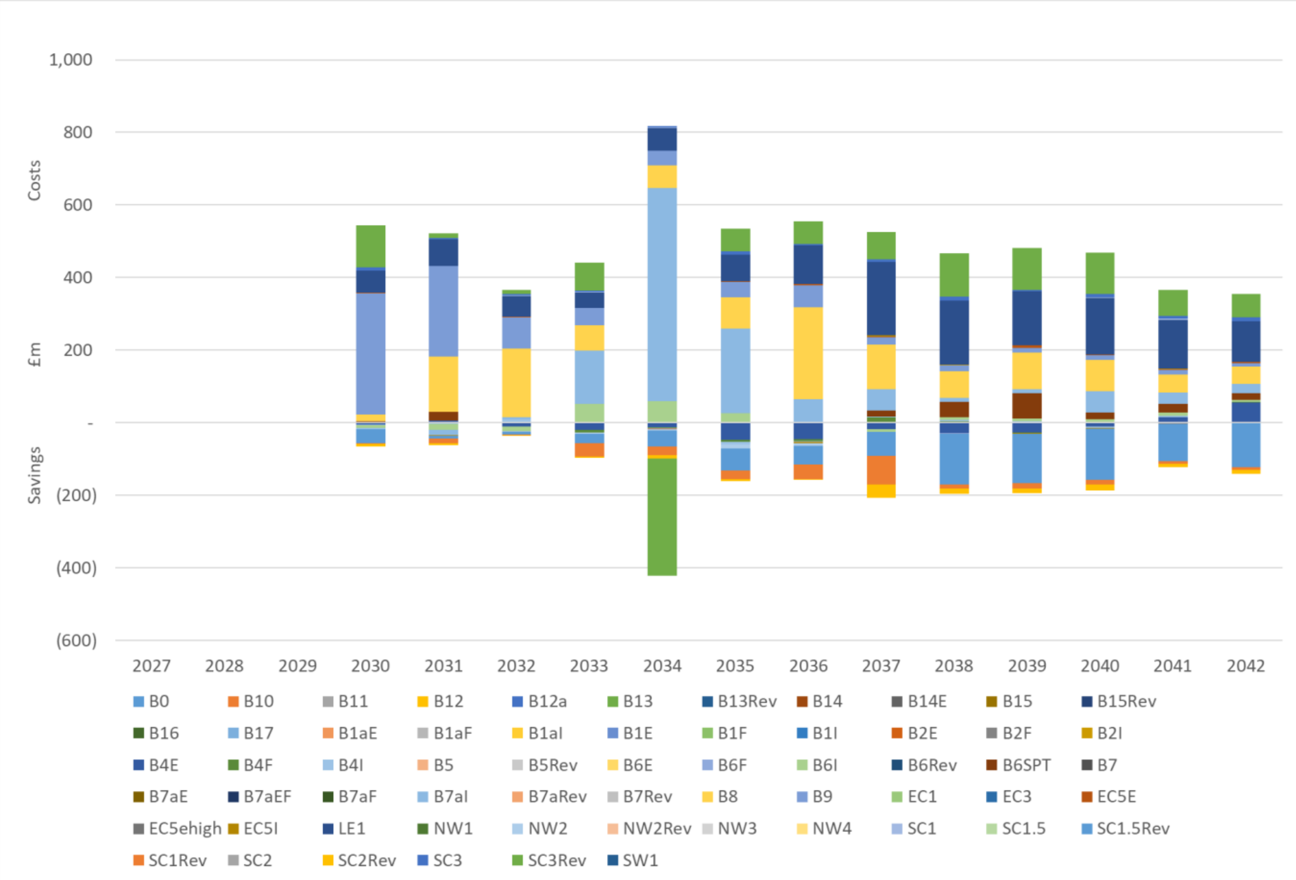


The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for Cronos for the First Additional case for the Falling Short scenario.

In general, Cronos increases constraint costs on several northern and southern boundaries but relieves congestion on another southern boundary. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis, constraint costs are higher on several northern boundaries

Figure 112: Change in constraint costs by boundary for Cronos for the Marginal Additional case for Leading the Way.

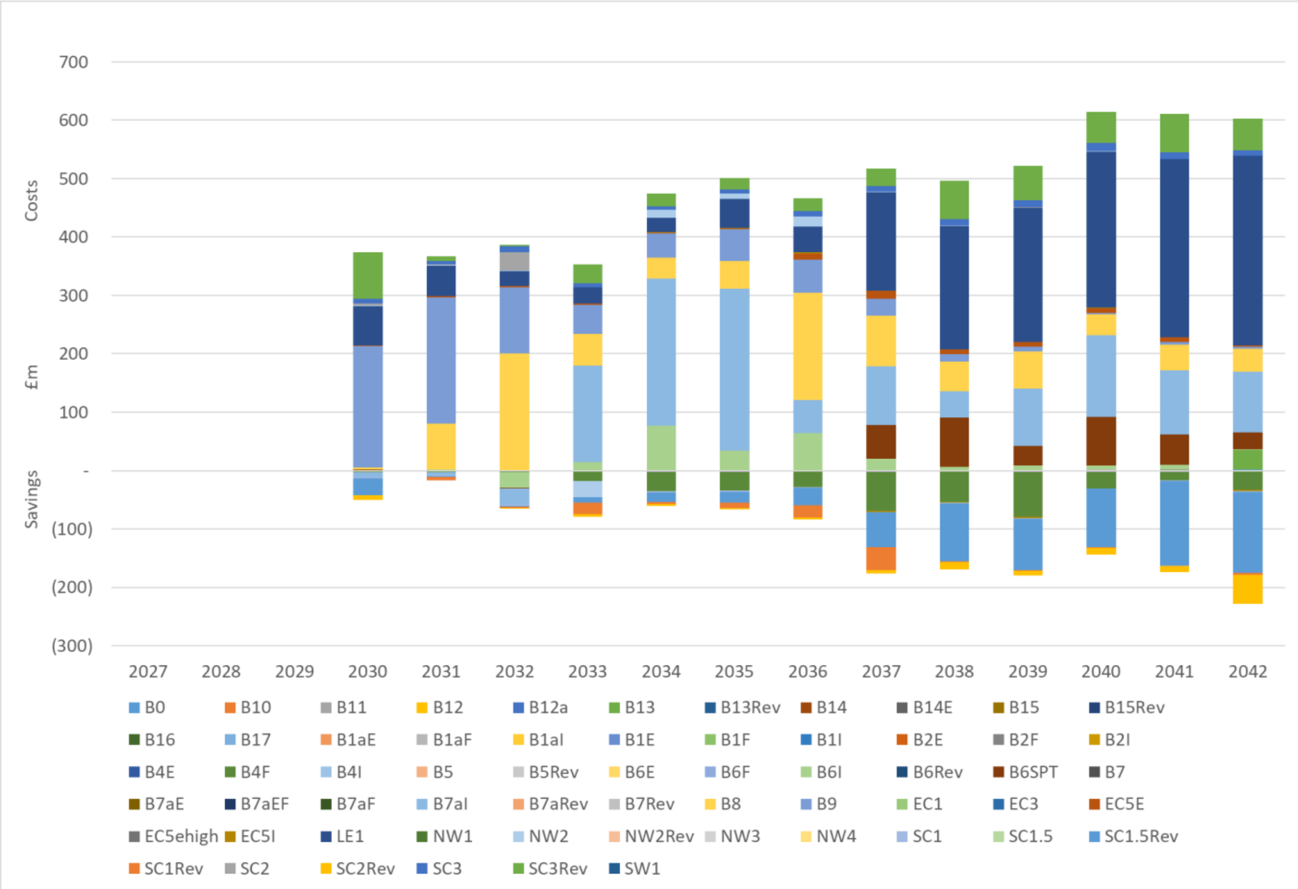


The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for Cronos for the Marginal Additional case for the Leading the Way scenario.

In general, Cronos increases constraint costs on several northern and southern boundaries but relieves congestion on certain other southern boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis, constraint costs are higher on several northern and southern boundaries.

Figure 113: Change in constraint costs by boundary for Cronos for the Marginal Additional case for Consumer Transformation.

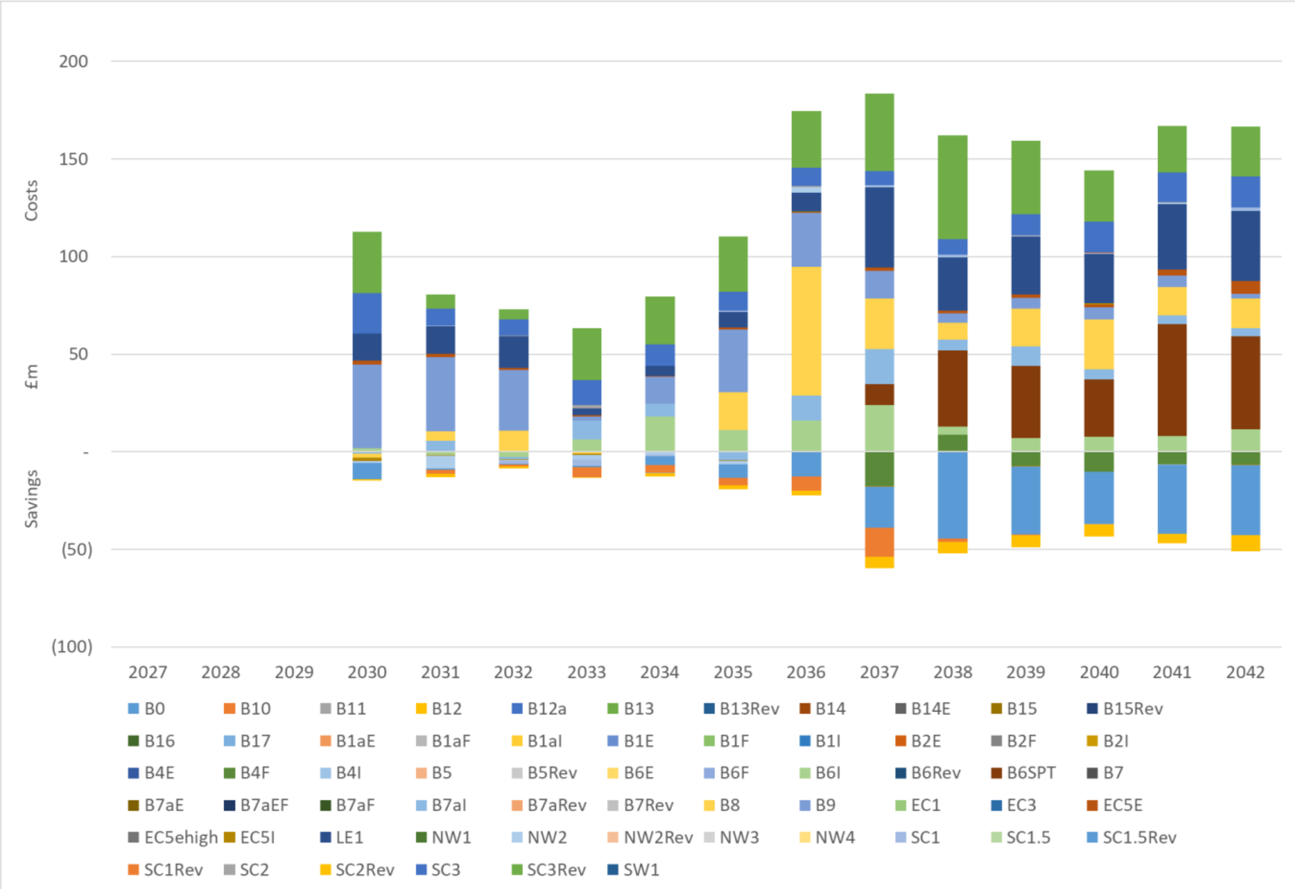


The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for Cronos for the Marginal Additional case for the Consumer Transformation scenario.

In general, Cronos increases constraint costs on several northern and southern boundaries but relieves congestion on certain other southern boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis, constraint costs are higher on several northern and southern boundaries.

Figure 114: Change in constraint costs by boundary for Cronos for the Marginal Additional case for Falling Short.



The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for Cronos for the Marginal Additional case for the Falling Short scenario.

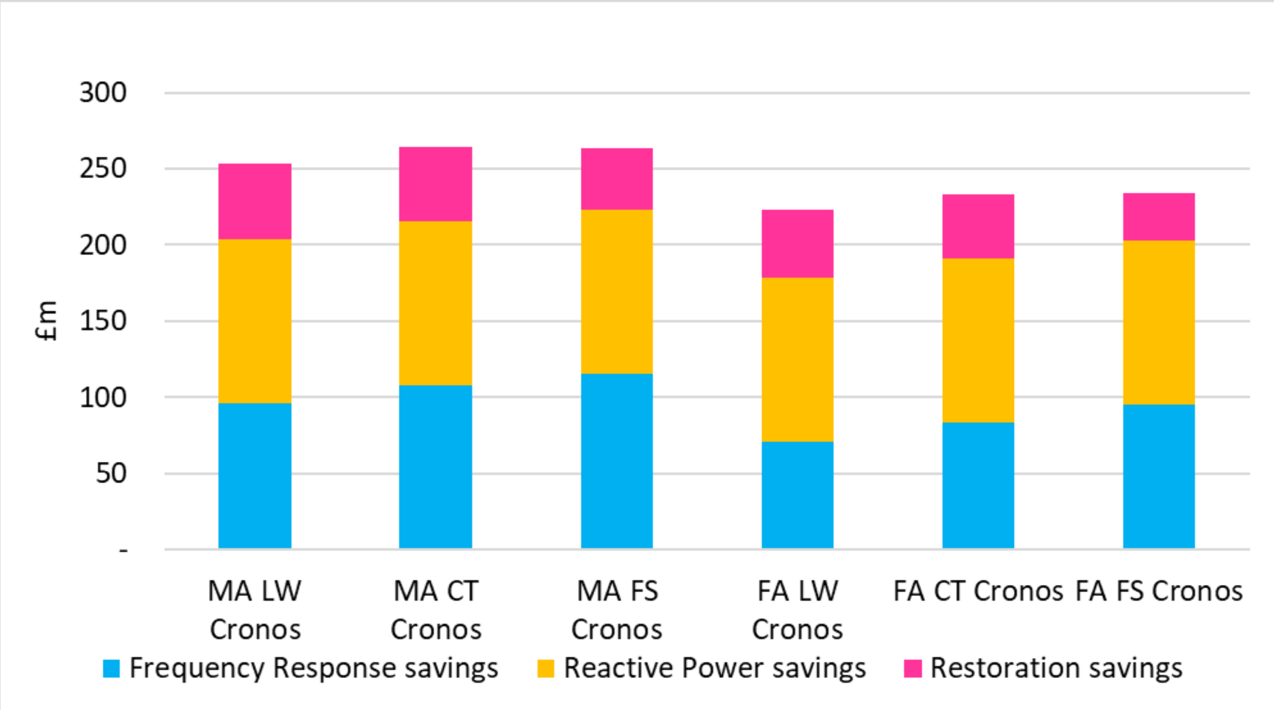
In general, Cronos increases constraint costs on several northern and southern boundaries but relieves congestion on certain other southern boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis, constraint costs are slightly higher on several northern boundaries.

PV system operation

Note: The modelling and analysis for system operation is the same as that within the March 2024 report. It was not necessary to repeat the work because the change in modelling assumptions would not produce a material change in the results.

Figure 115: PV potential system operability savings for Cronos, Present Value 25-year, real 2022, £m.

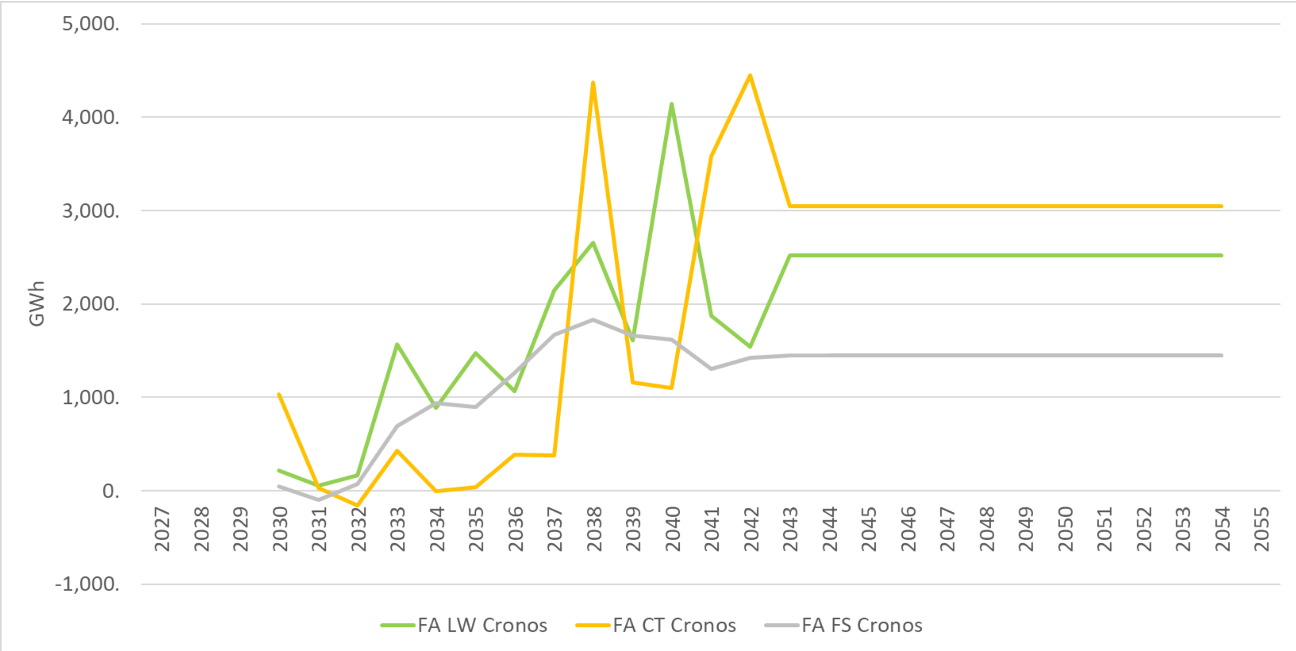


The above figure shows the potential savings for frequency response, reactive power and restoration services in present value (25-year, 2022 £m) for Cronos for Leading the Way, Consumer Transformation and Falling Short for both the Marginal Additional and First Additional cases. There is considerable uncertainty around forecasting potential system operability benefits over a 25-year time horizon, but the figure shows that there is potentially significant savings in frequency response, reactive power and restoration services.

There is little variation across the three scenarios and also across the First Additional and Marginal Additional cases. This is because the potential system operability savings from the services provided by Cronos are less sensitive to flows across the interconnector, whereas the constraint cost impact is highly dependent on the scale and direction of flows across the project.

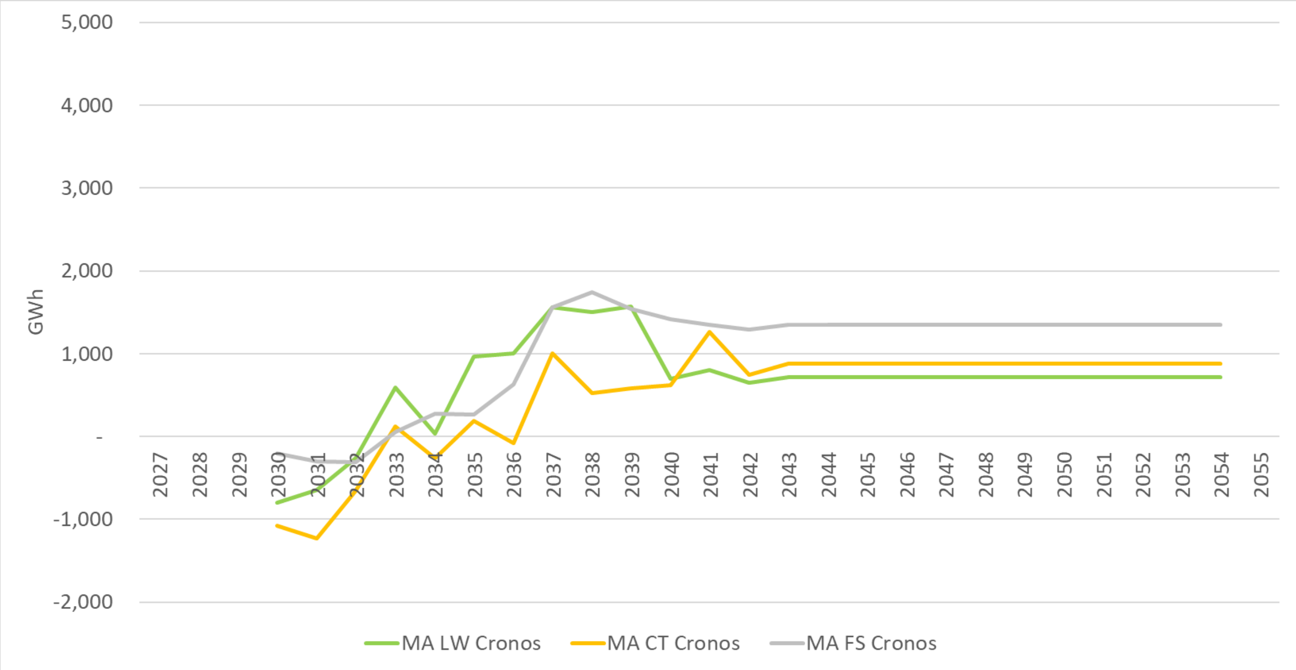
RES curtailment avoided

Figure 116: Annual RES curtailment avoided for Cronos for the First Additional case.



The above figure shows the renewable energy supply (RES) curtailment avoided on an annual basis for Leading the Way, Consumer Transformation and Falling Short for the First Additional case. Note that beyond 2042, the results are an average of the years 2040, 2041 and 2042, as our detailed modelling with FES22 only extends out to 2042. For the years 2030 to 2032 Cronos often results in very low RES curtailment avoided and occasionally increases RES curtailment: thereafter the level of annual RES curtailment avoided when Cronos is included is approximately between 0.5TWh and 4TWh, which equates to approximately between 1.4GWh and 11GWh per day.

Figure 117: Annual RES curtailment avoided for Cronos for the Marginal Additional case.



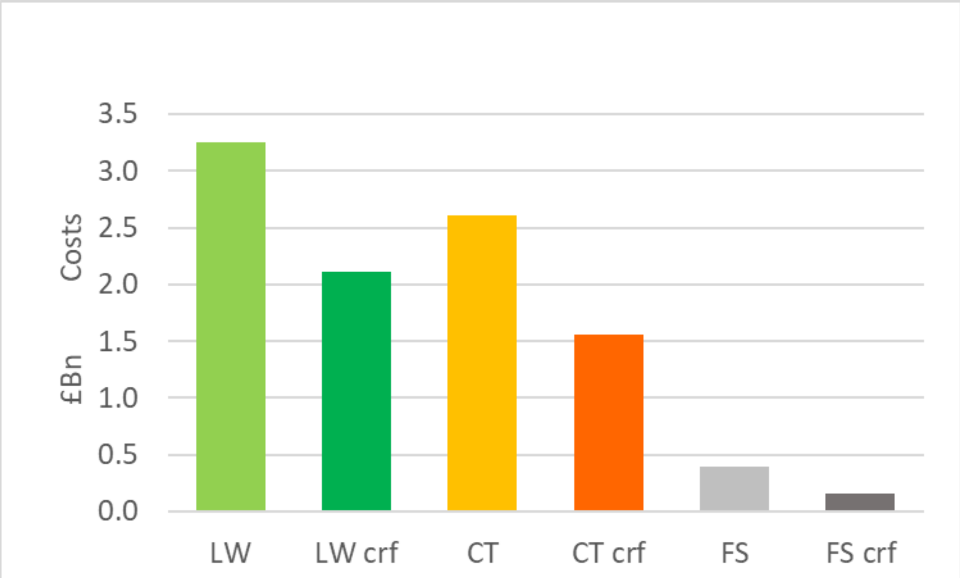
The above figure shows the renewable energy supply (RES) curtailment avoided on an annual basis for Leading the Way, Consumer Transformation and Falling Short for the Marginal Additional case. Note that beyond 2042, the results are an average of the years 2040, 2041 and 2042, as our detailed modelling with FES22 only extends out to 2042. The figure shows that the level of annual RES curtailment avoided when Cronos is included rises to approximately between 0.7TWh and 1.4TWh, which equates to approximately between 1.9GWh and 3.8GWh per day.

13. LionLink

LionLink is an Offshore Hybrid Asset (OHA) pilot project. It has a capacity of 1.8GW and connects to The Netherlands.

PV constraint costs

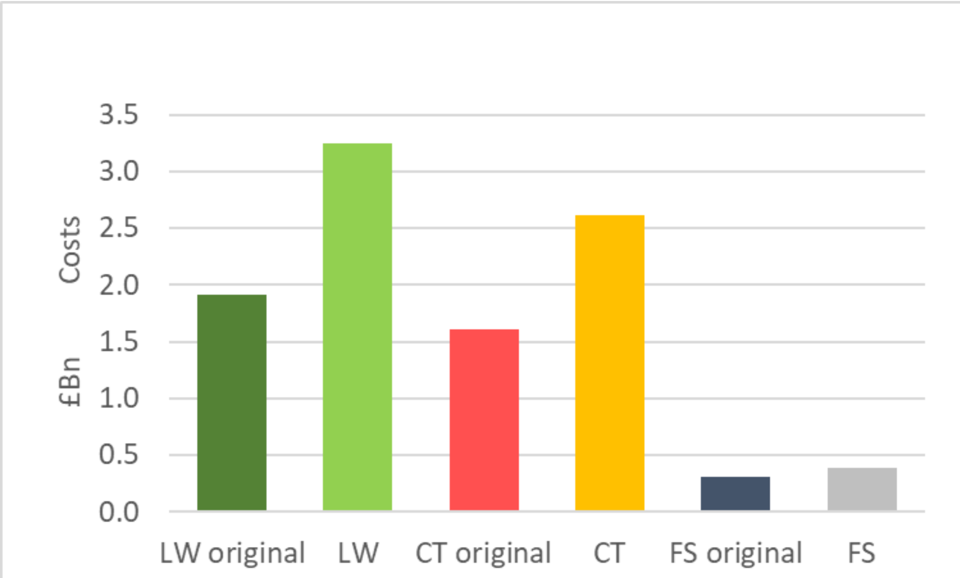
Figure 118: PV additional constraint costs due to LionLink for the First Additional case, Present Value 25-year, real 2022, £m, without and with Constraint Reduction Factor applied.



The above figure shows the additional constraint costs with the inclusion of LionLink for the FA case. Without the Constraint Reduction Factor applied, in the Leading the Way scenario (LW) constraint costs are increased by £3.2bn, in Consumer Transformation (CT) by £2.6bn and in the Falling Short (FS) scenario by £0.4bn.

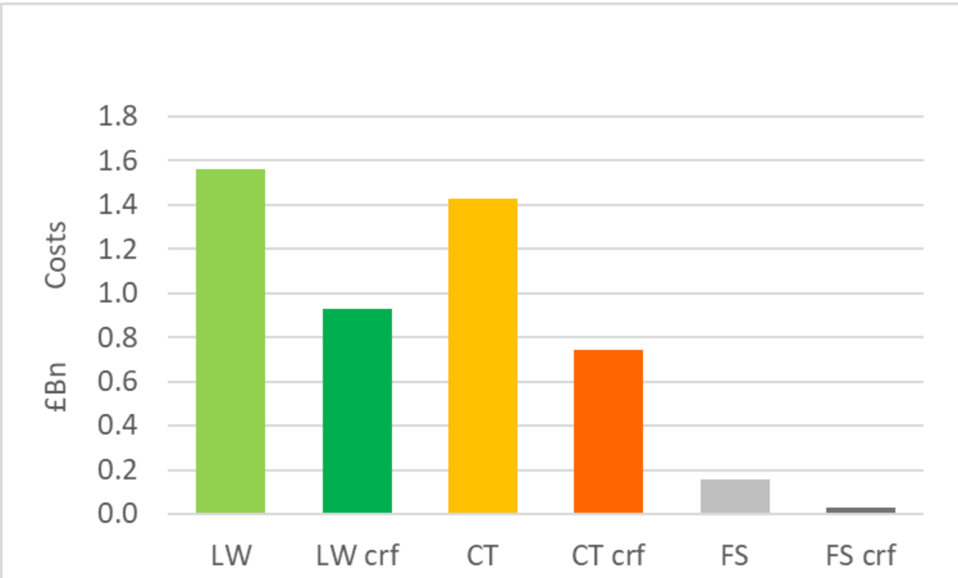
With the Constraint Reduction Factor applied, in the Leading the Way scenario (LW) constraint costs are increased by £2.1bn, in Consumer Transformation (CT) by £1.6bn and in the Falling Short (FS) scenario by £0.2bn.

Figure 119: PV additional constraint costs due to LionLink for the First Additional case, Present Value 25-year, real 2022, £m, for the original analysis (March 2024) and for Nautilus at Grain with 1.4GW link and Irish demand and generation from TYNDP.



The above figure shows that the changes made to the scenarios, that is the reduction in the capacity of the link connecting the Nautilus offshore platform to Belgium from 3.5GW to 1.4GW and the change in Irish demand and generation to reflect final TYNDP data results in a significant increase in constraint costs in LW and CT.

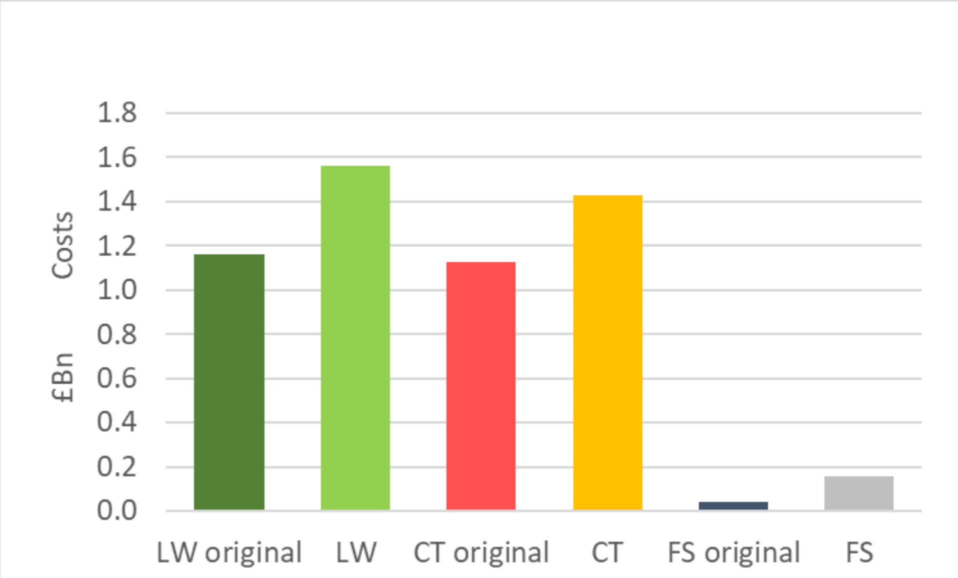
Figure 120: PV additional constraint costs due to LionLink for the Marginal Additional case, Present Value 25-year, real 2022, £m, without and with Constraint Reduction Factor applied.



The above figure shows the additional constraint costs with the inclusion of LionLink for the MA case. Without the Constraint Reduction Factor applied, in the Leading the Way scenario (LW) constraint costs are increased by £1.6bn, in Consumer Transformation (CT) by £1.4bn and in the Falling Short (FS) scenario by £0.15bn.

With the Constraint Reduction Factor applied, in the Leading the Way scenario (LW) constraint costs are increased by £0.9bn, in Consumer Transformation (CT) by £0.7bn and in the Falling Short (FS) scenario by £0.03bn.

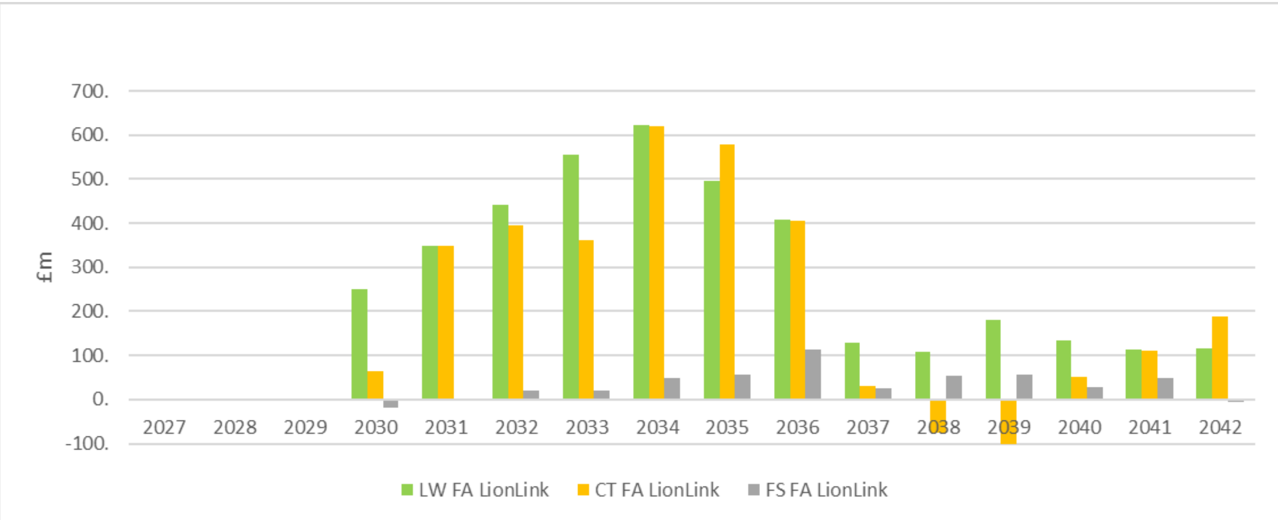
Figure 121: PV additional constraint costs due to LionLink for the Marginal Additional case, Present Value 25-year, real 2022, £m, for the original analysis (March 2024) and for Nautilus at Grain with 1.4GW link and Irish demand and generation from TYNDP.



The above figure shows that the changes made to the scenarios, that is the reduction in the capacity of the link connecting the Nautilus offshore platform to Belgium from 3.5GW to 1.4GW and the change in Irish demand and generation to reflect final TYNDP data results in a significant increase in constraint costs in LW and CT.

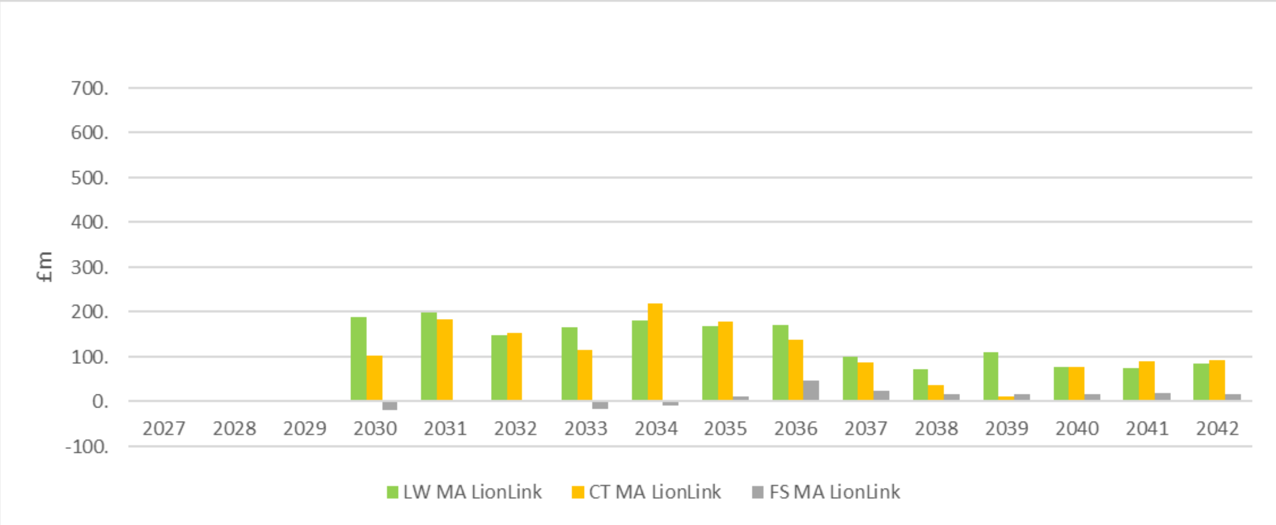
Annual constraint costs (undiscounted)

Figure 122: Additional annual constraint costs (undiscounted) due to LionLink for the First Additional case.



The above figure shows that LionLink results in an increase in constraint costs of approximately £300m to £600m (undiscounted) in CT and LW for the years 2031 to 2036. CT shows some constraint savings in 2038 and 2039. In FS constraint cost increases are very much lower, with small savings in 2030. The results are significantly higher than the original (March 2024) results in the early to mid-2030s.

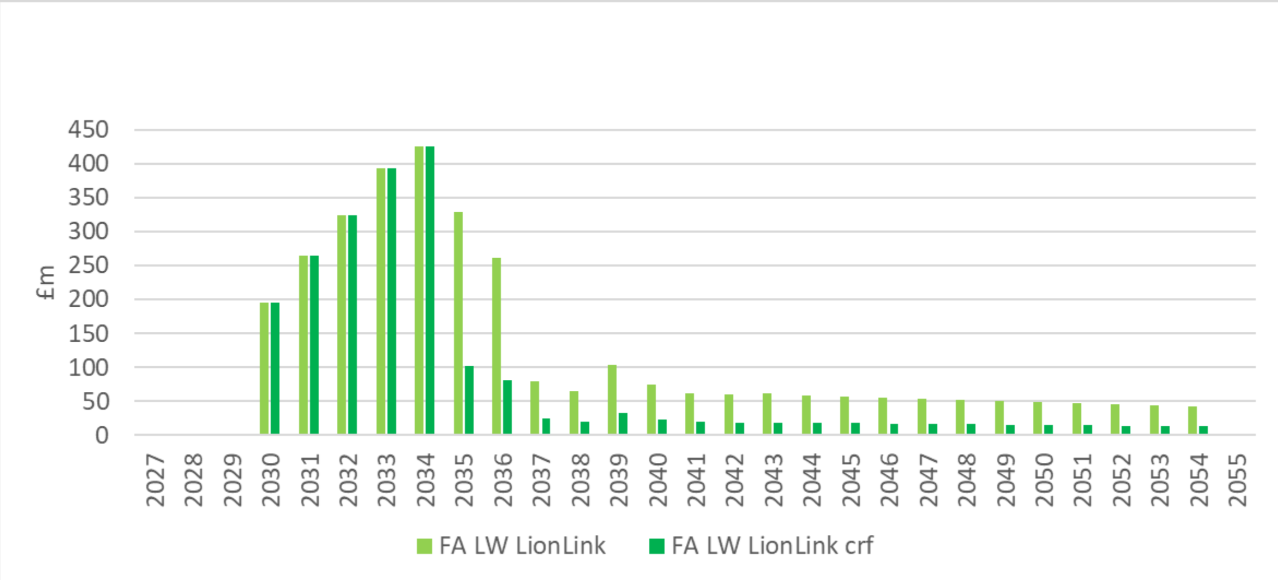
Figure 123: Additional annual constraint costs (undiscounted) due to LionLink for the Marginal Additional case.



In the Marginal Additional case, LionLink results in an increase in constraint costs of approximately £100m to £200m (undiscounted) in CT and LW for the years 2030 to 2036. FS shows constraint savings for the years 2030, 2031, 2033 and 2034 and for the other years shows very low levels of additional constraint costs compared to LW and CT. The results are higher than the original (March 2024) results.

Annual constraint costs (discounted), without and with Constraint Reduction Factor

Figure 124: Additional annual constraint costs (discounted) due to LionLink for the First Additional case for Leading the Way, without and with Constraint Reduction Factor applied.



The above chart shows the additional constraint costs without and with the Constraint Reduction Factor (CRF) applied for the Leading the Way scenario for the First Additional case. The chart shows the impact of the CRF being applied from 2035 onwards.

Figure 125: Additional annual constraint costs (discounted) due to LionLink for the First Additional case for Consumer Transformation, without and with Constraint Reduction Factor applied.

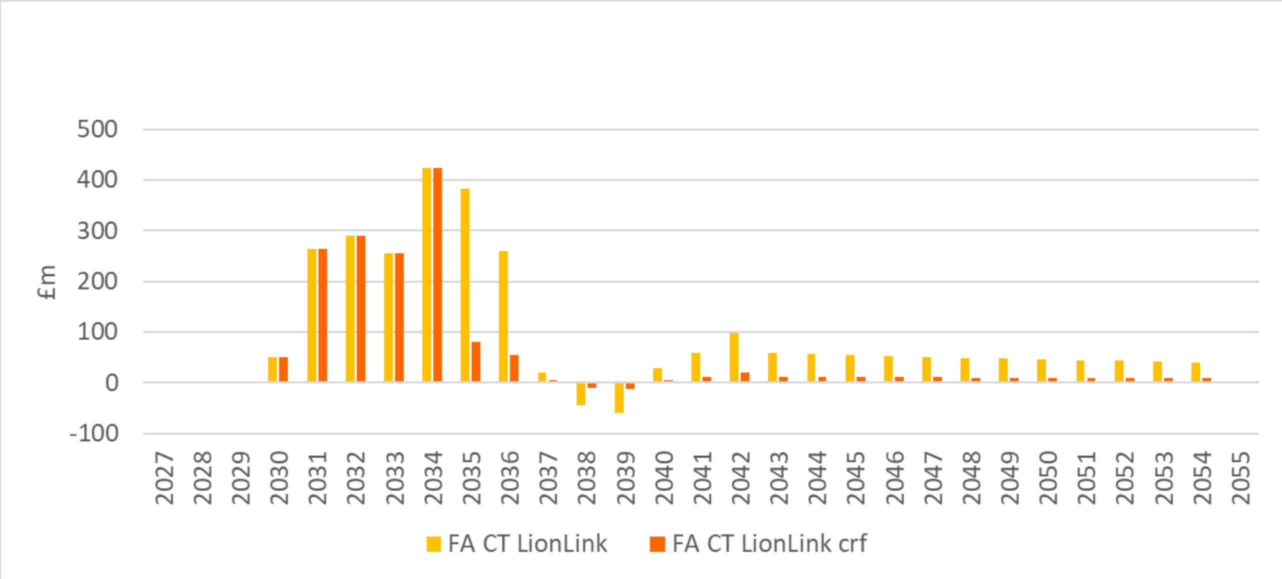
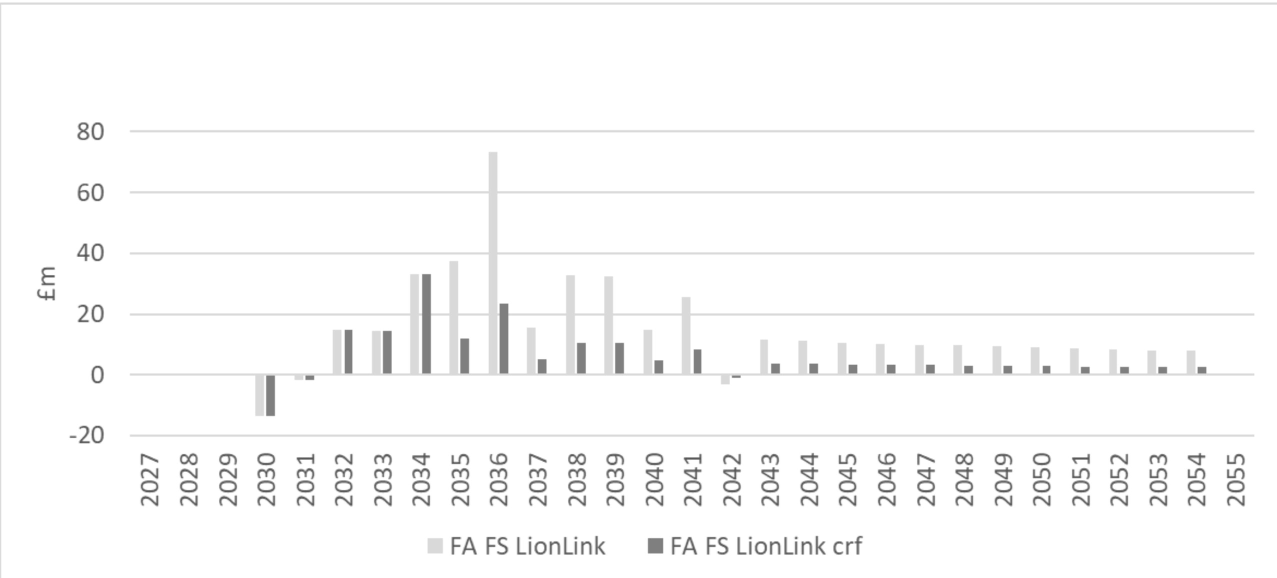
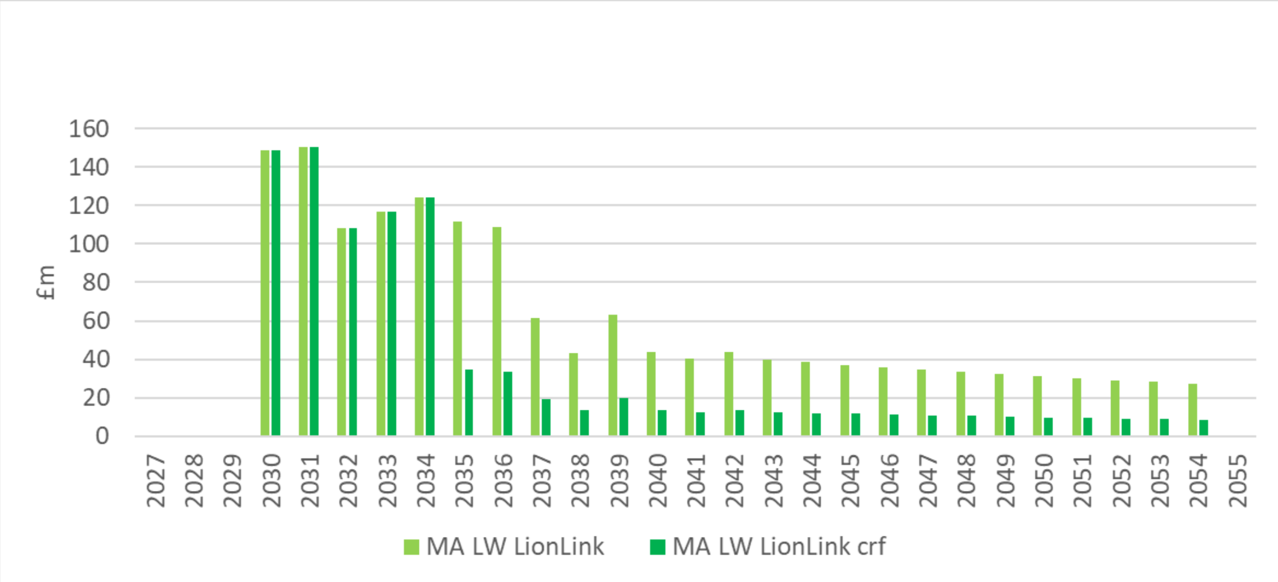


Figure 126: Additional annual constraint costs (discounted) due to LionLink for the First Additional case for Falling Short, without and with Constraint Reduction Factor applied.



The above chart shows the additional constraint costs without and with the Constraint Reduction Factor (CRF) applied. The chart shows the impact of the CRF being applied from 2035 onwards.

Figure 127: Additional annual constraint costs (discounted) due to LionLink for the Marginal Additional case for Leading the Way, without and with Constraint Reduction Factor applied.



The above chart shows the additional constraint costs without and with the Constraint Reduction Factor (CRF) applied for the Leading the Way scenario for the Marginal Additional case. The chart shows the impact of the CRF being applied from 2035 onwards.

Figure 128: Additional annual constraint costs (discounted) due to LionLink for the Marginal Additional case for Consumer Transformation, without and with Constraint Reduction Factor applied.

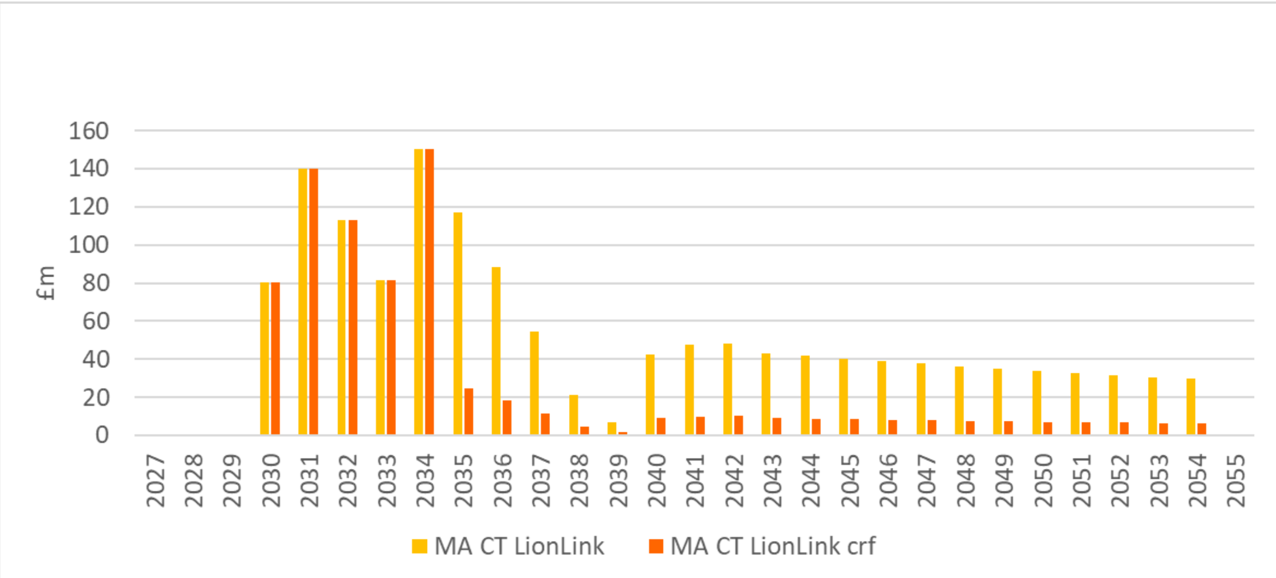
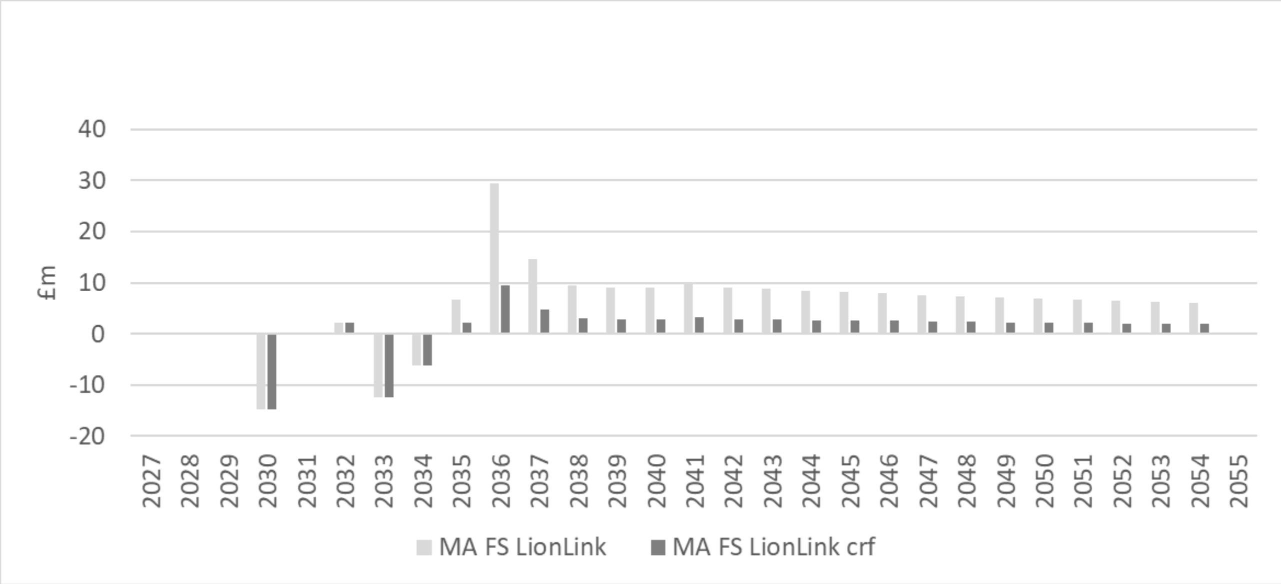
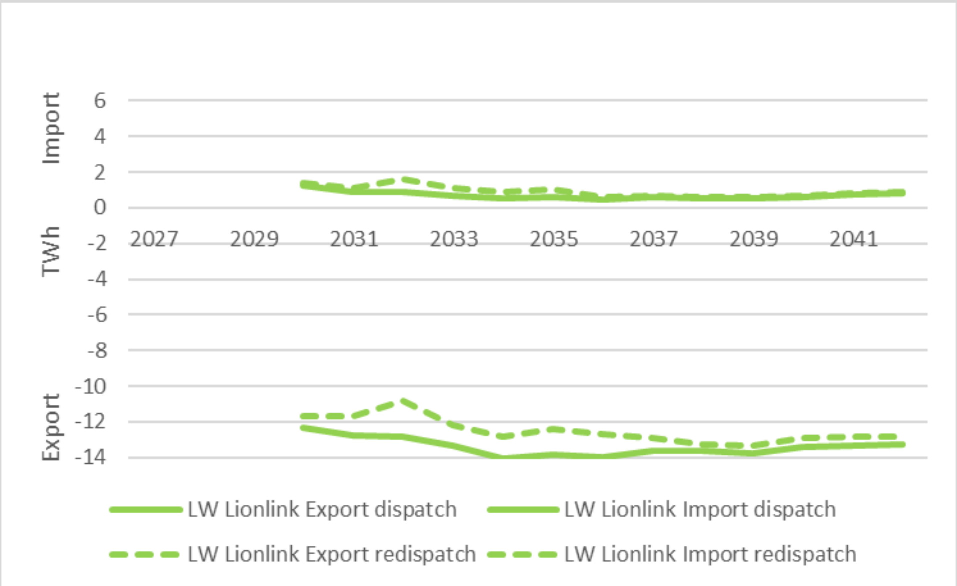


Figure 129: Additional annual constraint costs (discounted) due to LionLink for the Marginal Additional case for Falling Short, without and with Constraint Reduction Factor applied.



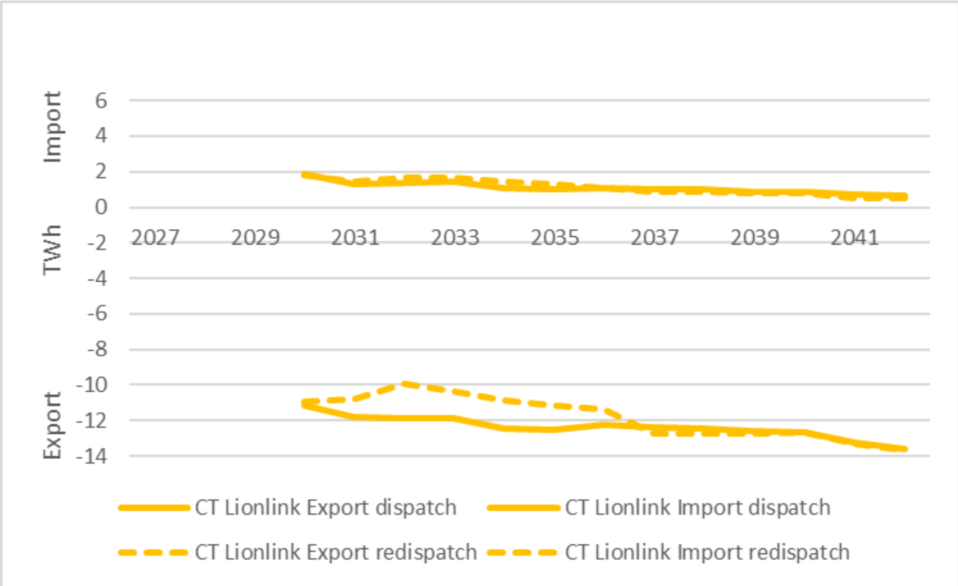
Annual import and export flows for dispatch and redispatch

Figure 130: Annual import and export flows for LionLink in the FA case for Leading the Way.



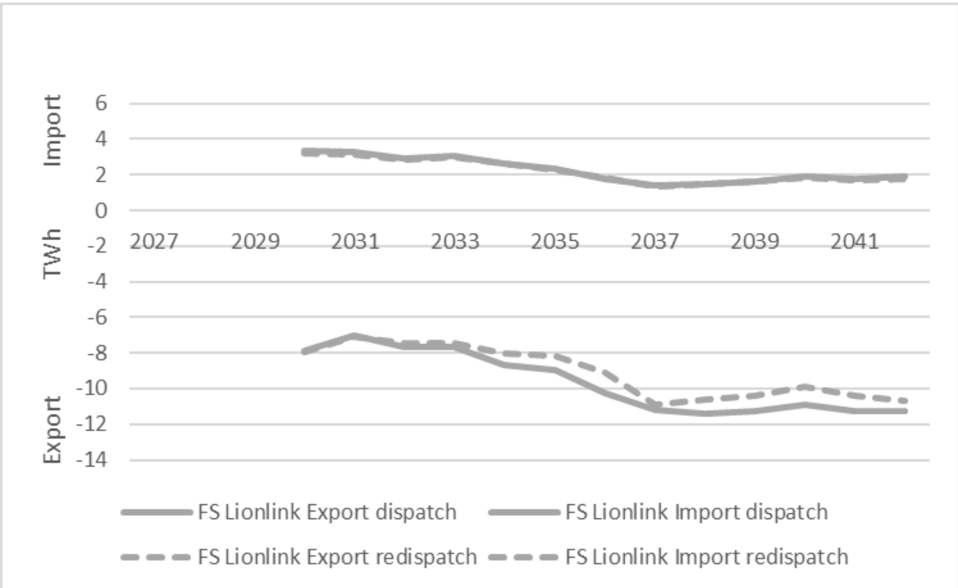
The above figure shows very high exports and low imports in the dispatch. The redispatch shows a reduction in exports and a very slight increase in imports. Compared to the original (March 2024) results, exports are substantially higher and imports are slightly lower.

Figure 131: Annual import and export flows for LionLink in the FA case for Consumer Transformation.



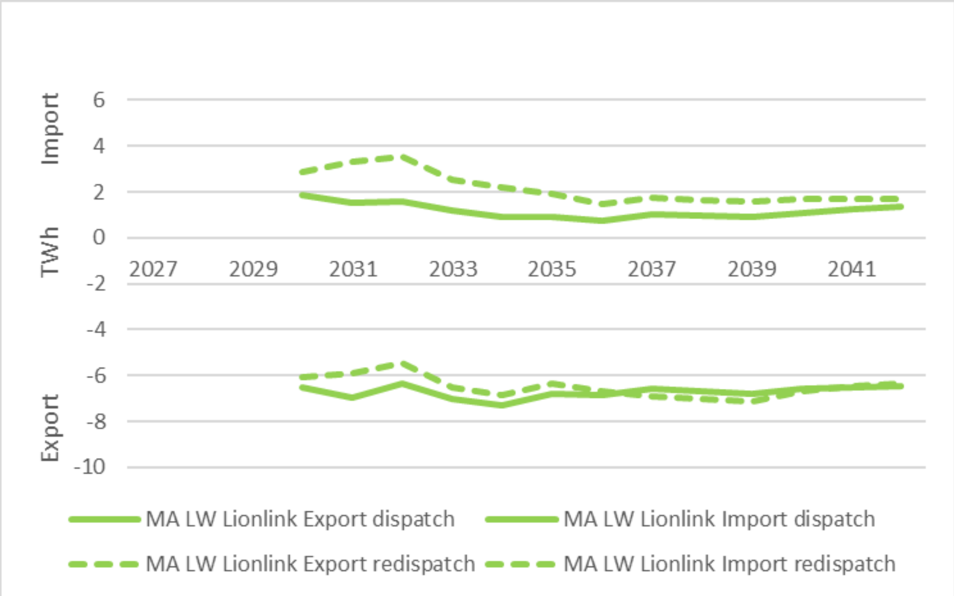
The above figure shows very high exports and low imports in the dispatch. The redispatch shows a reduction in exports and little change in imports. Compared to the original (March 2024) results, exports are substantially higher and imports are slightly lower.

Figure 132: Annual import and export flows for LionLink in the FA case for Falling Short.



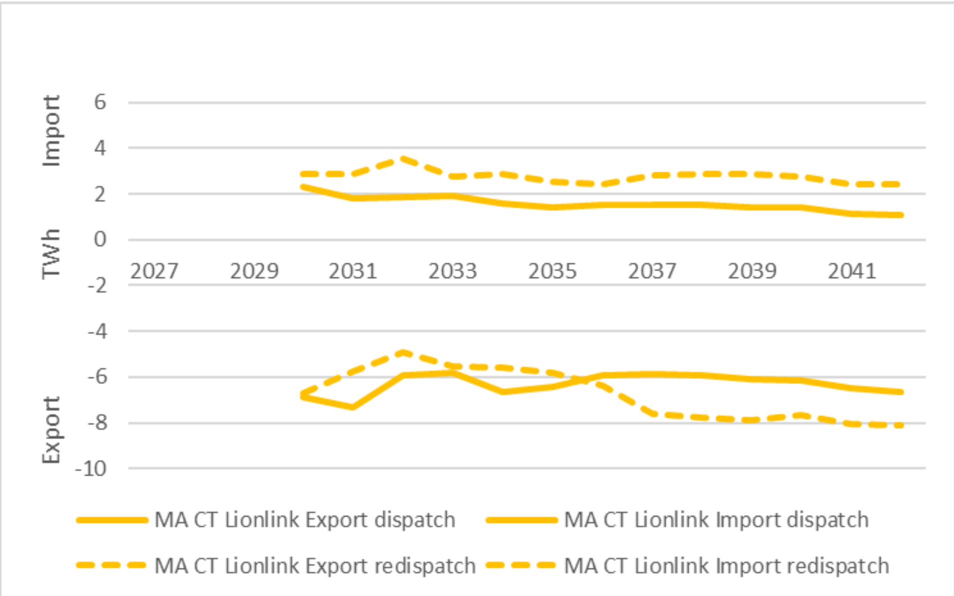
The above figure shows that for the First Additional case LionLink has increasing levels of exports over the forecast period up to 2038 for Falling Short. The redispatch shows a slight reduction in exports after 2031. Compared to the original (March 2024) results, exports are substantially higher and imports are lower.

Figure 133: Annual import and export flows for LionLink in the MA case for Leading the Way.



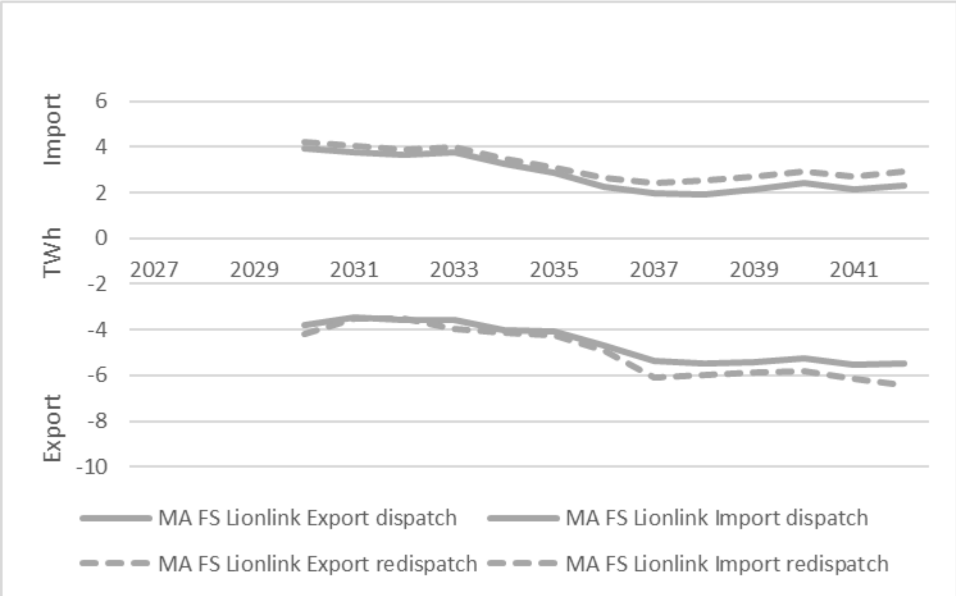
The above figure shows for the dispatch high exports, but lower than in the FA case, and low imports, similar to the FA case. The redispatch shows a slight change in export levels and an increase in imports. Compared to the original (March 2024) results, exports are marginally higher and imports are slightly lower.

Figure 134: Annual import and export flows for LionLink in the MA case for Consumer Transformation.



The above figure shows high exports, but significantly lower than in the FA case, and low imports in the dispatch, similar to the FA case. The redispatch shows a mixture of increases and reductions in export levels and an increase in imports. Compared to the original (March 2024) results, exports are slightly higher and imports are similar.

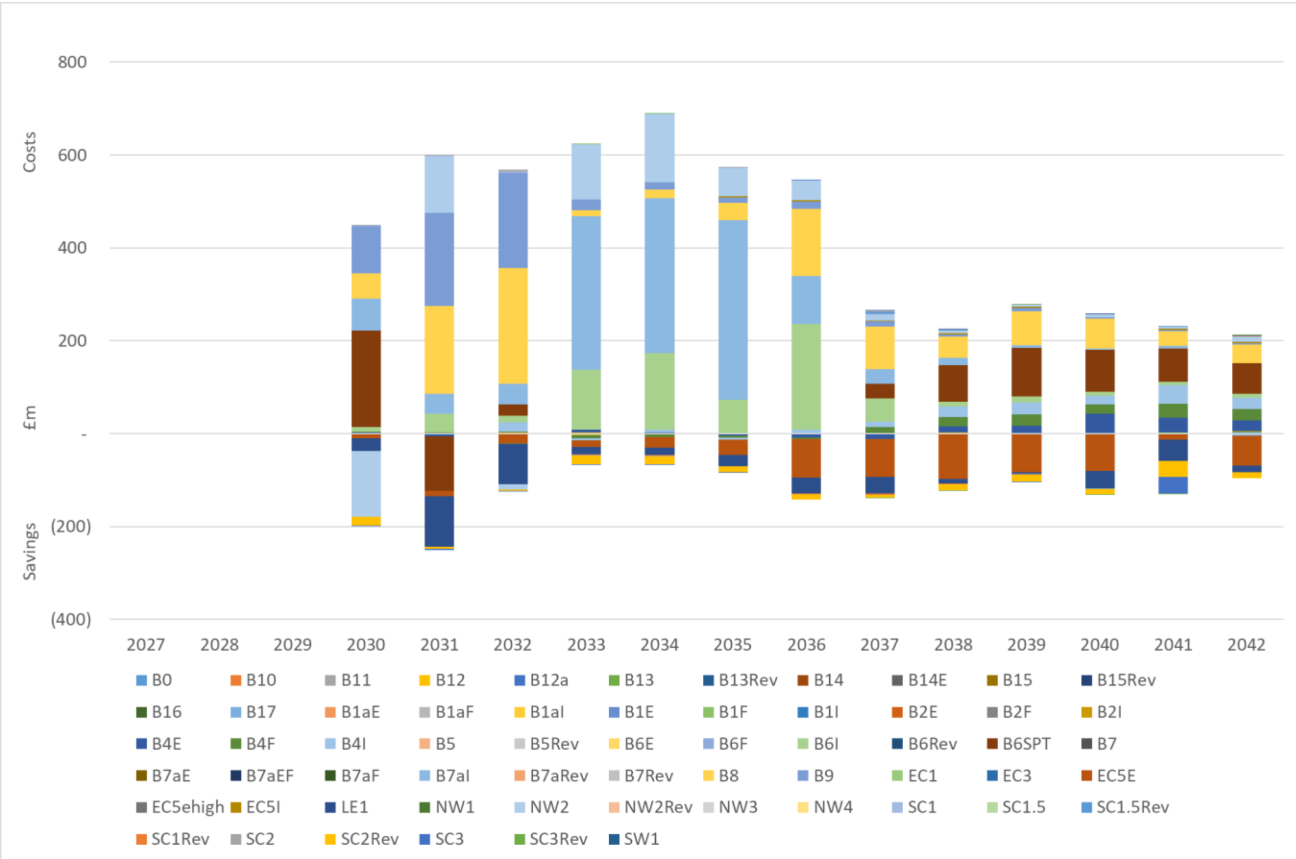
Figure 135: Annual import and export flows for LionLink in the MA case for Falling Short.



The above figure shows that for the Marginal Additional case, LionLink has increasing exports, but substantially lower than in the First Additional case, and decreasing imports in the dispatch, which are slightly higher than those in FA. The redispatch shows some increase in exports, especially in the later years and a small increase in imports. Compared to the original (March 2024) results, exports and imports are similar.

Change in constraint costs by boundary

Figure 136: Change in constraint costs by boundary for LionLink for the First Additional case for Leading the Way.



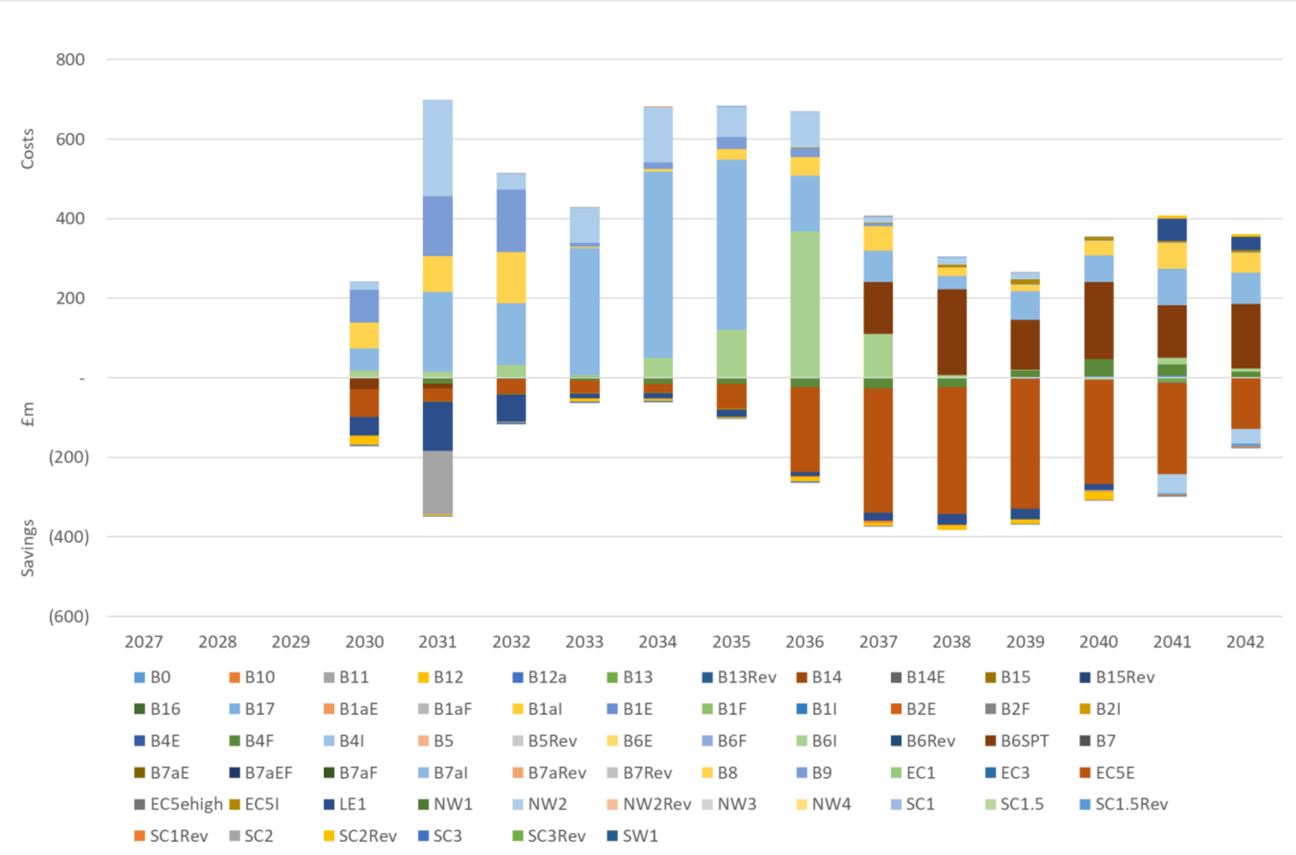
The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for LionLink for the First Additional case for the Leading the Way scenario. Each different colour represents the change in constraint costs for a particular boundary. It is important to note that the chart shows changes in constraint costs by boundary, i.e. the difference between constraint costs when the project is included and when the project is excluded.

The figure shows that LionLink increases constraint costs on certain boundaries but also reduces constraint costs on others. Whether the impact is an increase in constraint costs or a reduction in constraint costs for a particular boundary, changes from year to year. The size of change in constraint costs by boundary can also vary significantly from year to year. This is shown clearly in the years 2036 to 2037. The figure also shows that the specific boundaries that have the greatest impact on the total change in constraint costs can vary from year to year. These factors are a result of the changes in demand, supply and network capability over time.

In general, LionLink increases constraint costs on several northern, midland and southern boundaries, but relieves congestion on certain northern, southern and eastern boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis, constraint costs are significantly higher on several northern and southern boundaries.

Figure 137: Change in constraint costs by boundary for LionLink for the First Additional case for Consumer Transformation.

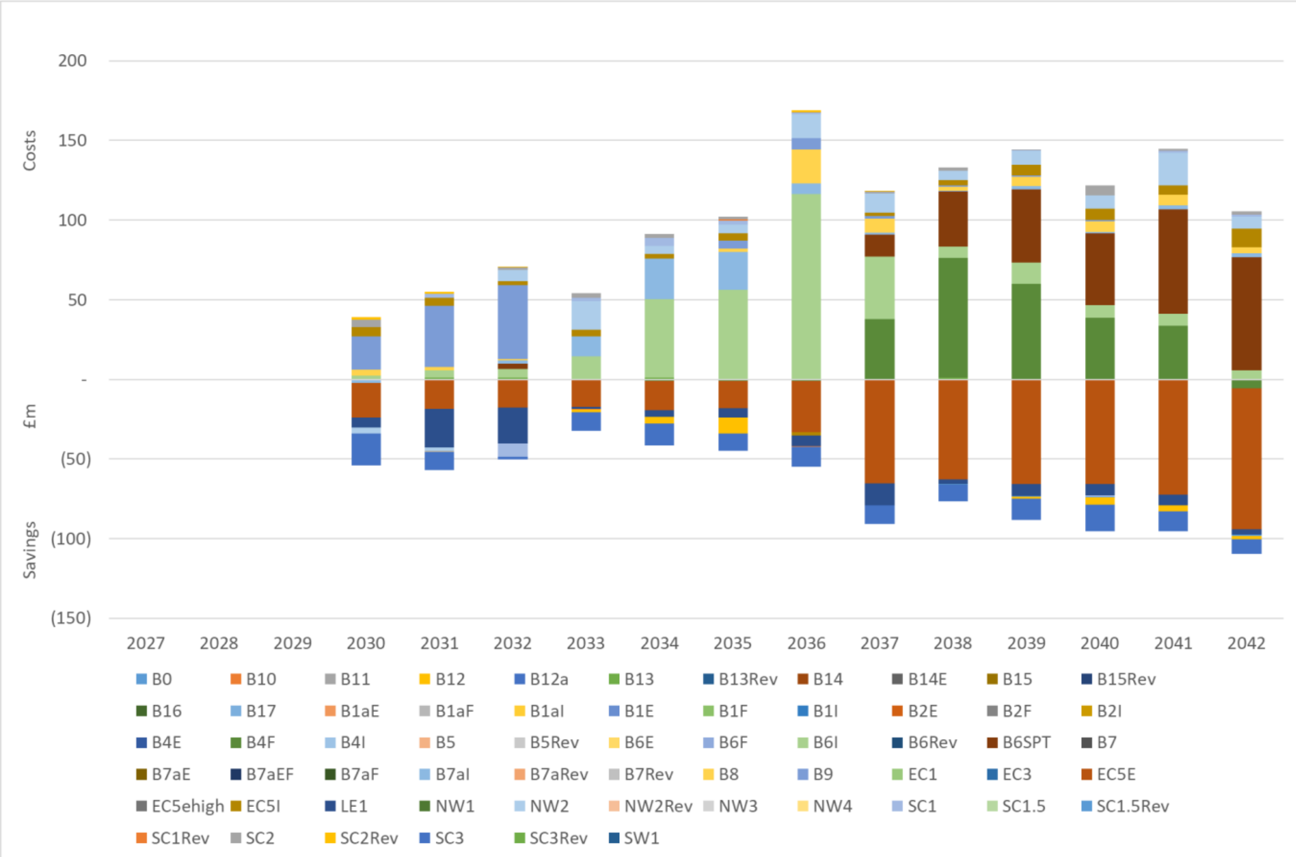


The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for LionLink for the First Additional case for the Consumer Transformation scenario.

In general, LionLink increases constraint costs on several northern and southern boundaries but relieves congestion one particular eastern boundary in the later years. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis, constraint costs are higher on several northern boundaries.

Figure 138: Change in constraint costs by boundary for LionLink for the First Additional case for Falling Short.



The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for LionLink for the First Additional case for the Falling Short scenario.

In general, LionLink increases constraint costs on several northern and midland boundaries but relieves congestion on one particular eastern boundary. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis, constraint costs are higher on several northern boundaries.

Figure 139: Change in constraint costs by boundary for LionLink for the Marginal Additional case for Leading the Way.

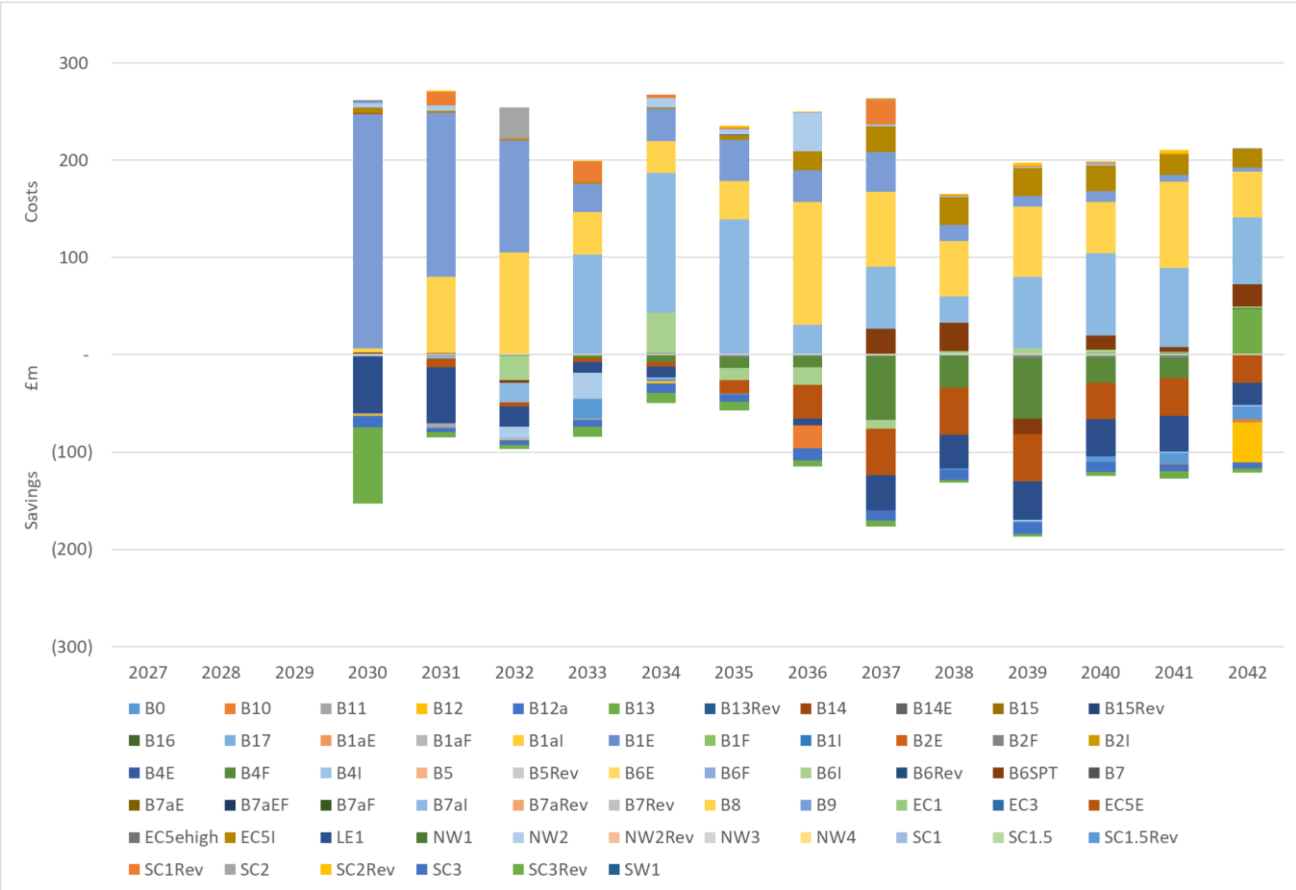
The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for LionLink for the Marginal Additional case for the Leading the Way scenario.

In general, LionLink increases constraint costs on several northern boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

LionLink also relieves congestion on one particular southern boundary in 2034. The saving only occurs for a single year suggesting the combination of supply, demand and boundary capabilities that enable such a significant saving across one boundary when LionLink is included only exist for that year. That is in later years, supply and demand patterns and boundary capabilities will have evolved such that the model is no longer able to produce the lowest total cost solution by significantly reducing constraint costs across that particular boundary when LionLink is included.

Compared to the original (March 2024) analysis, constraint costs are higher on several northern boundaries.

Figure 140: Change in constraint costs by boundary for LionLink for the Marginal Additional case for Consumer Transformation.

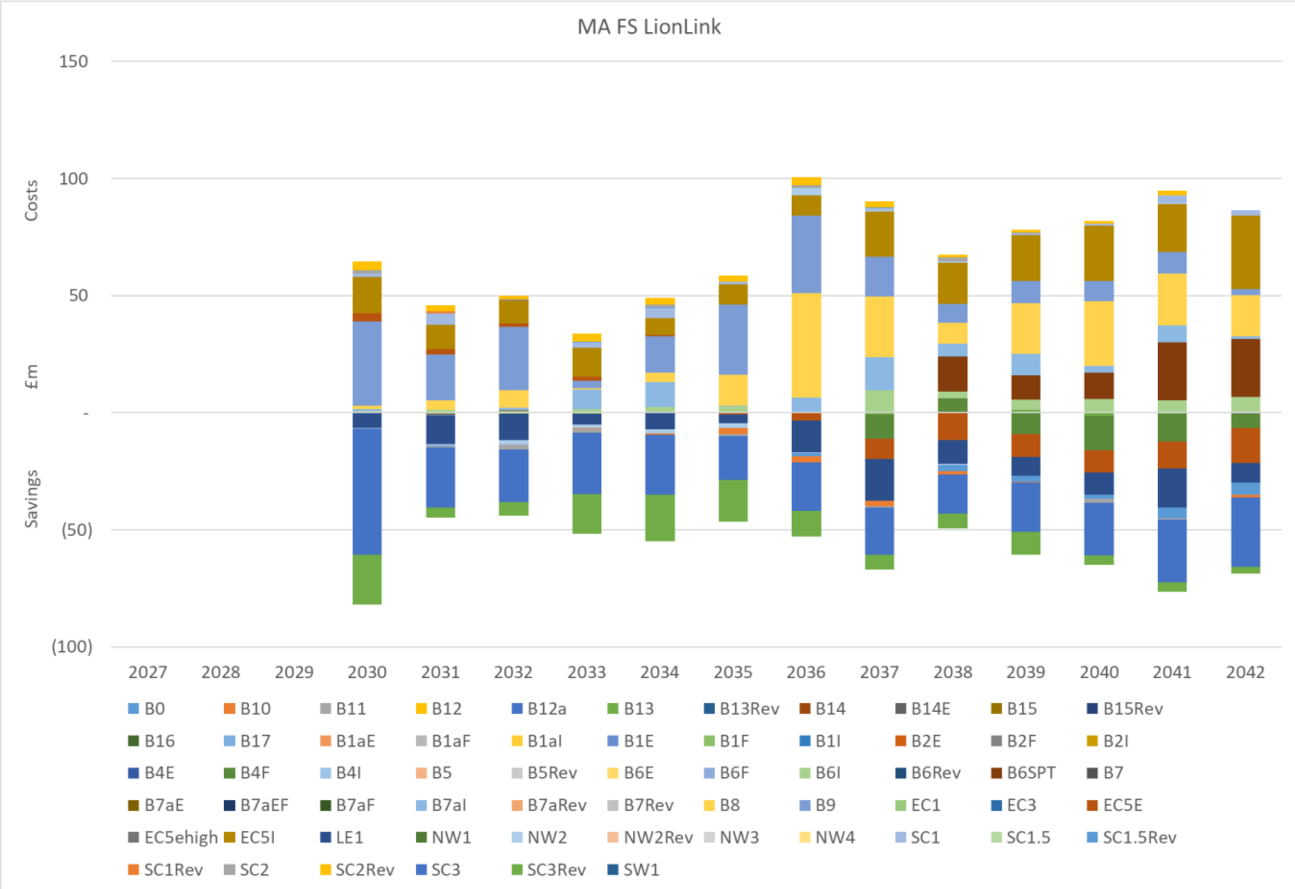


The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for LionLink for the Marginal Additional case for the Consumer Transformation scenario.

In general, LionLink increases constraint costs on several northern and midland boundaries but relieves congestion on various boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis, constraint costs are higher on several northern and midland boundaries.

Figure 141: Change in constraint costs by boundary for LionLink for the Marginal Additional case for Falling Short.



The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for LionLink for the Marginal Additional case for the Falling Short scenario.

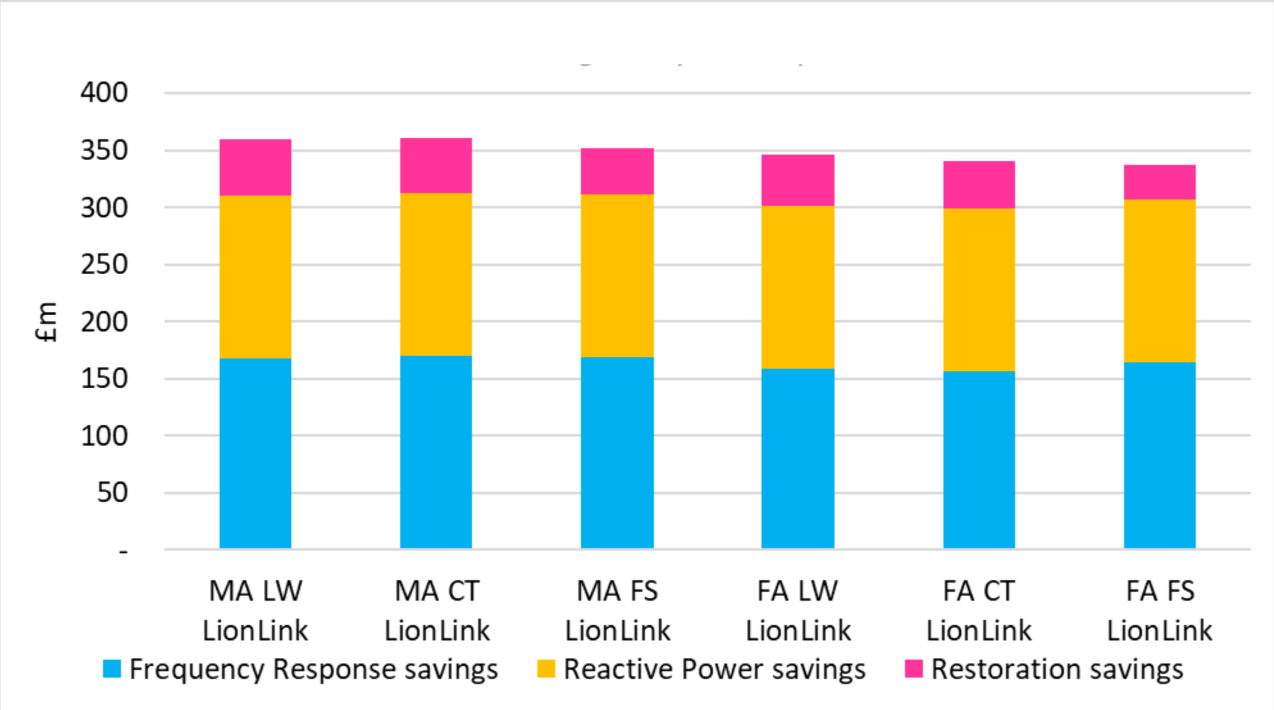
In general, LionLink increases constraint costs on several northern boundaries, but relieves congestion on certain southern and eastern boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis constraint costs are slightly higher on several northern boundaries.

PV system operation

Note: The modelling and analysis for system operation is the same as that within the March 2024 report. It was not necessary to repeat the work because the change in modelling assumptions would not produce a material change in the results.

Figure 142: PV potential system operability savings for LionLink, Present Value 25-year, real 2022, £m.

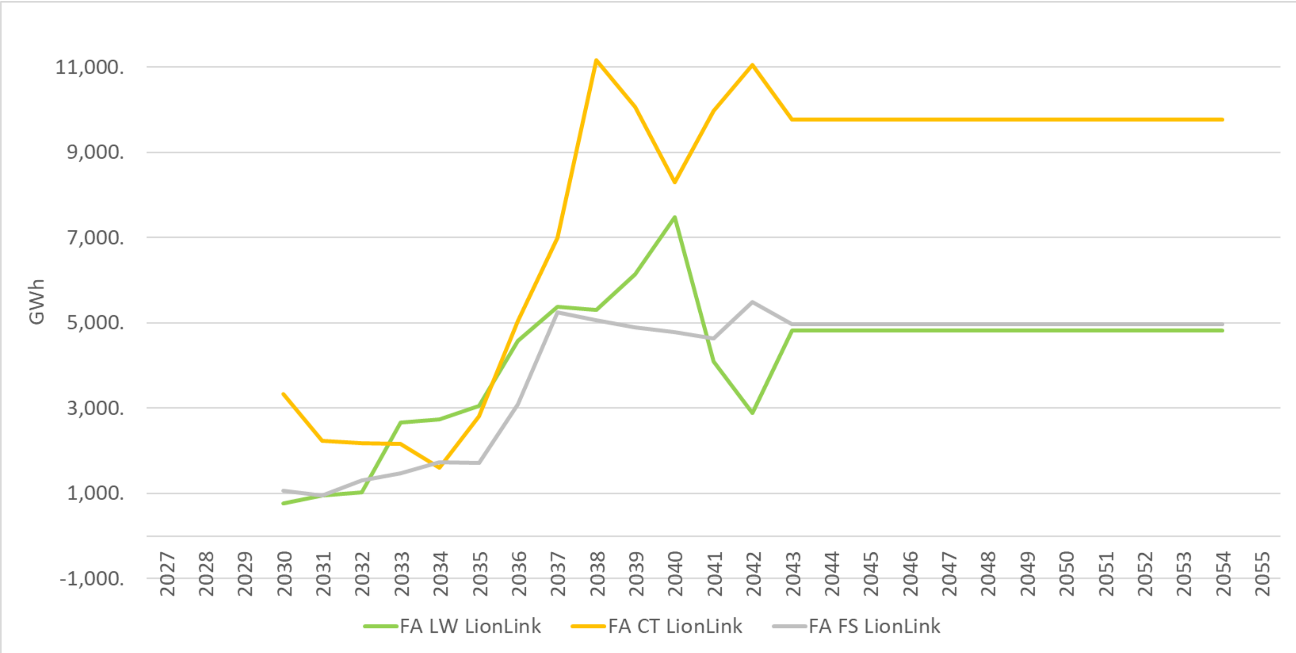


The above figure shows the potential savings for frequency response, reactive power and restoration services in present value (25-year, 2022 £m) for LionLink for Leading the Way, Consumer Transformation and Falling Short for both the Marginal Additional and First Additional cases. There is considerable uncertainty around forecasting potential system operability benefits over a 25-year time horizon, but the figure shows that there is potentially significant savings in frequency response, reactive power and restoration services.

There is little variation across the three scenarios and also across the First Additional and Marginal Additional cases. This is because the potential system operability savings from the services provided by LionLink are less sensitive to flows across the interconnector, whereas the constraint cost impact is highly dependent on the scale and direction of flows across the project.

RES curtailment avoided

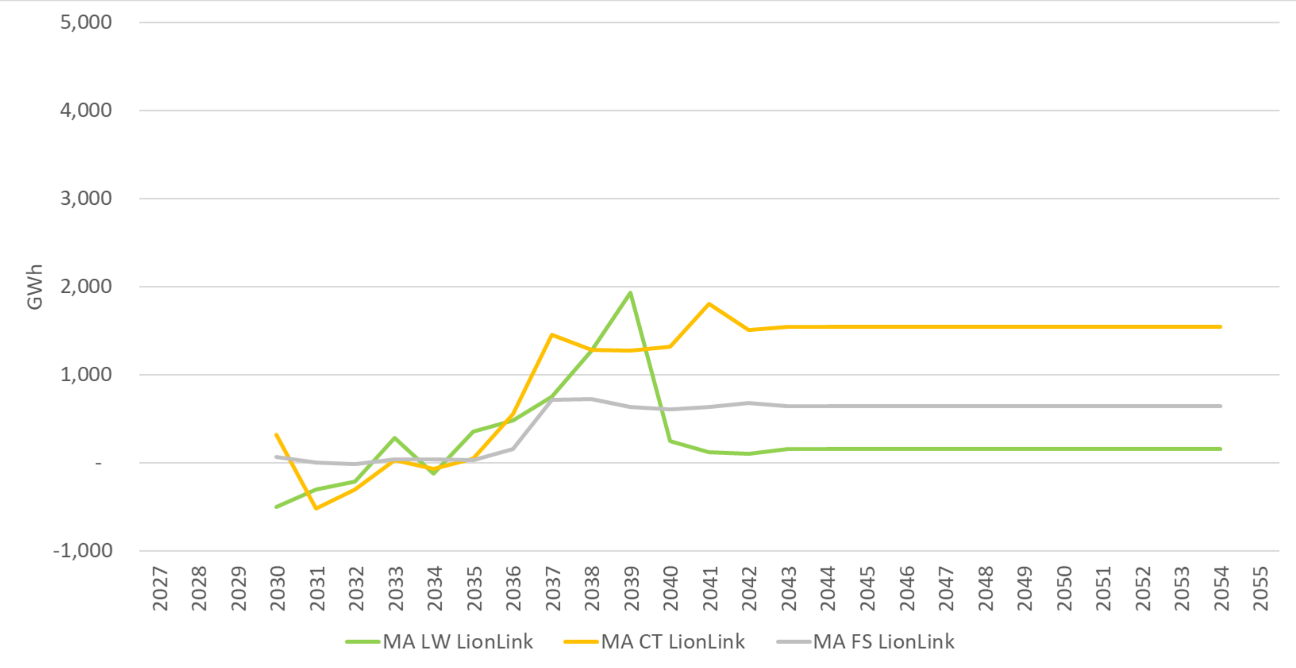
Figure 143: Annual RES curtailment avoided for LionLink for the First Additional case.



The above figure shows the renewable energy supply (RES) curtailment avoided on an annual basis for Leading the Way, Consumer Transformation and Falling Short for the First Additional case. Note that beyond 2042, the results are an average of the years 2040, 2041 and 2042, as our detailed modelling with FES22 only extends out to 2042. The figure shows that the level of annual RES curtailment avoided when LionLink is included is approximately between 1TWh and 10TWh, which equates to approximately between 2.7GWh and 27GWh per day.

Compared to the original (March 2024) results LionLink shows a substantial increase in the levels of RES curtailment avoided in the FA case for all three scenarios. This is due to the substantial increase in exports.

Figure 144: Annual RES curtailment avoided for LionLink for the Marginal Additional case.



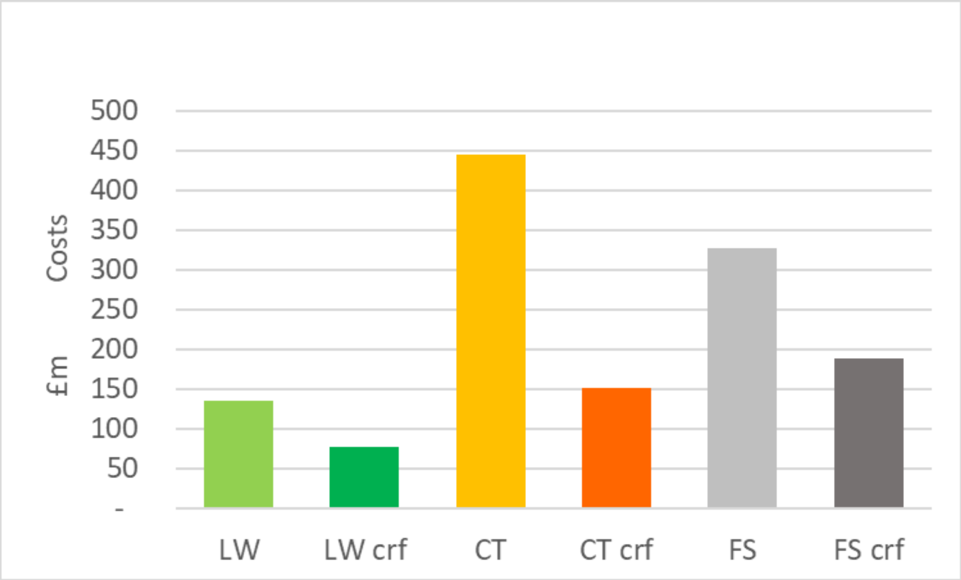
The above figure shows the renewable energy supply (RES) curtailment avoided on an annual basis for Leading the Way, Consumer Transformation and Falling Short for the Marginal Additional case. Note that beyond 2042, the results are an average of the years 2040, 2041 and 2042, as our detailed modelling with FES22 only extends out to 2042. The figure shows that for the years 2030 to 2035, there is often an increase in RES curtailment: thereafter the level of annual RES curtailment avoided when LionLink is included varies approximately between 0.1TWh and 1.5TWh, which equates to approximately between 0.3GWh and 4.1GWh per day.

14. LirIC

LirIC is a W3 interconnector project. It has a capacity of 700MW and connects to Northern Ireland.

PV constraint costs

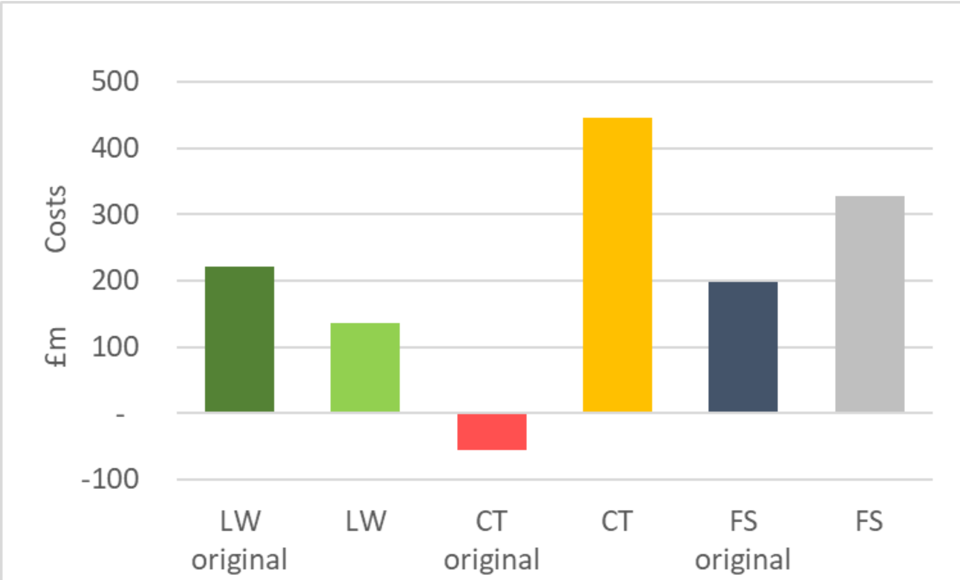
Figure 145: PV additional constraint costs due to LirIC for the First Additional case, Present Value 25-year, real 2022, £m, without and with Constraint Reduction Factor applied.



The above figure shows the additional constraint costs with the inclusion of LirIC for the FA case. Without the Constraint Reduction Factor applied, in the Leading the Way scenario (LW) constraint costs are increased by £0.14bn, in Consumer Transformation (CT) by £0.45bn and in the Falling Short (FS) scenario by £0.33bn.

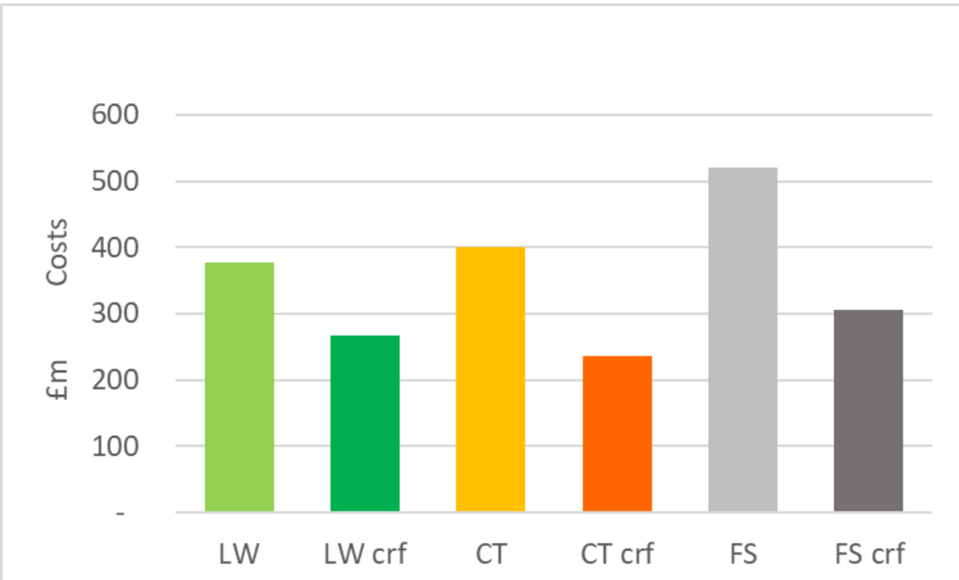
With the Constraint Reduction Factor applied, in the Leading the Way scenario (LW) constraint costs are increased by £0.08bn, in Consumer Transformation (CT) by £0.15bn and in the Falling Short (FS) scenario by £0.19bn.

Figure 146: PV additional constraint costs due to LirIC for the First Additional case, Present Value 25-year, real 2022, £m, for the original analysis (March 2024) and for Nautilus at Grain with 1.4GW link and Irish demand and generation from TYNDP.



The above figure shows that the changes made to the scenarios, that is the reduction in the capacity of the link connecting the Nautilus offshore platform to Belgium from 3.5GW to 1.4GW and the change in Irish demand and generation to reflect final TYNDP data results in a reduction in additional constraint costs in LW but a significant increase in constraint costs in CT and FS. For CT, in the original (March 2024) analysis the inclusion of LirIC slightly reduced constraint costs, whereas in the latest analysis LirIC increases constraint costs by £450m.

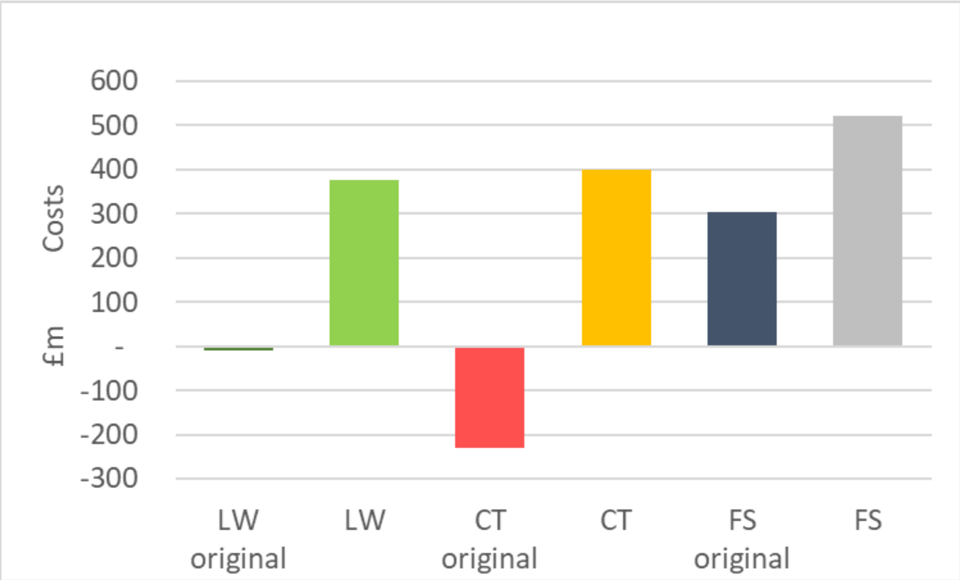
Figure 147: PV additional constraint costs due to LirIC for the Marginal Additional case, Present Value 25-year, real 2022, £m, without and with Constraint Reduction Factor applied.



The above figure shows the additional constraint costs with the inclusion of LirIC for the MA case. Without the Constraint Reduction Factor applied, in the Leading the Way scenario (LW) constraint costs are increased by £0.38bn, in Consumer Transformation (CT) by £0.4bn and in the Falling Short (FS) scenario by £0.52bn.

With the Constraint Reduction Factor applied, in the Leading the Way scenario (LW) constraint costs are increased by £0.26bn, in Consumer Transformation (CT) by £0.24bn and in the Falling Short (FS) scenario by £0.31bn.

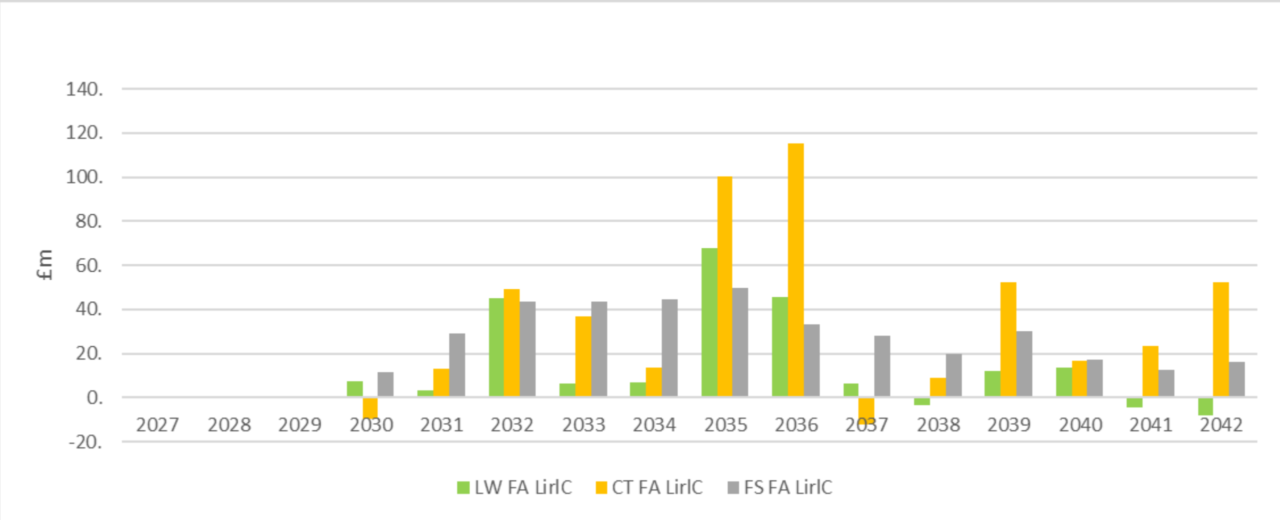
Figure 148: PV additional constraint costs due to LirIC for the Marginal Additional case, Present Value 25-year, real 2022, £m, for the original analysis (March 2024) and for Nautilus at Grain with 1.4GW link and Irish demand and generation from TYNDP.



The above figure shows that the changes made to the scenarios, that is the reduction in the capacity of the link connecting the Nautilus offshore platform to Belgium from 3.5GW to 1.4GW and the change in Irish demand and generation to reflect final TYNDP data results in a significant increase in constraint costs in all three scenarios. In the original (March 2024) analysis the inclusion of LirIC reduced constraint costs in LW and CT by £11m and £231m respectively but in the latest analysis the inclusion of LirIC increases constraint costs by £380m and £400m.

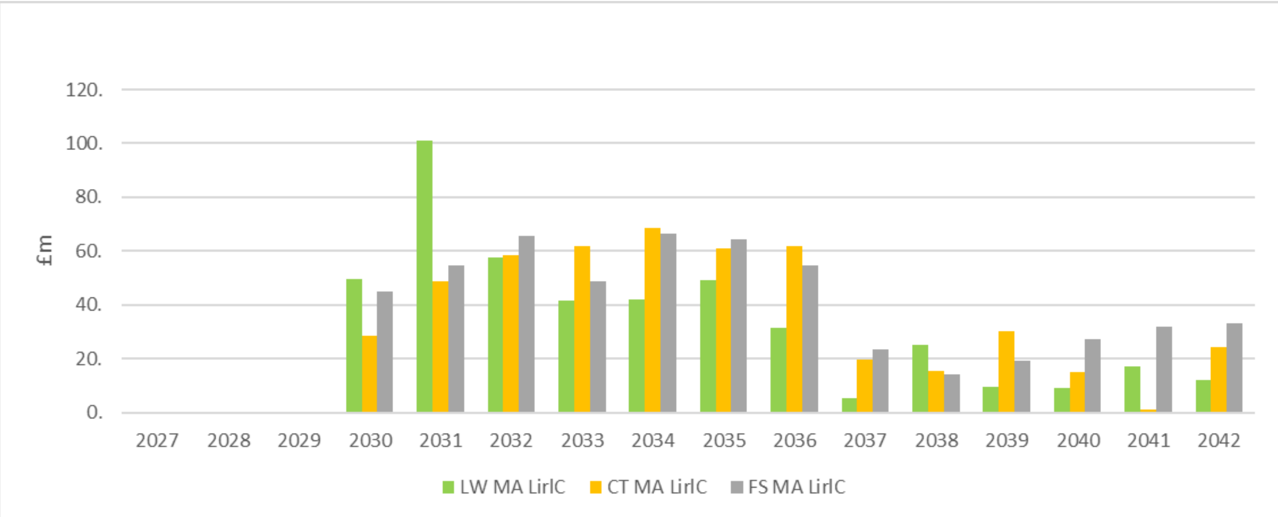
Annual constraint costs (undiscounted)

Figure 149: Additional annual constraint costs (undiscounted) due to LirIC for the First Additional case.



The above figure shows that the impact on constraint costs of the inclusion of LirIC is variable. Results vary from year to year, with both LW and CT showing several years where the inclusion of LirIC reduces constraint costs. The results are significantly higher than the original (March 2024) results for CT, higher for FS but lower for LW.

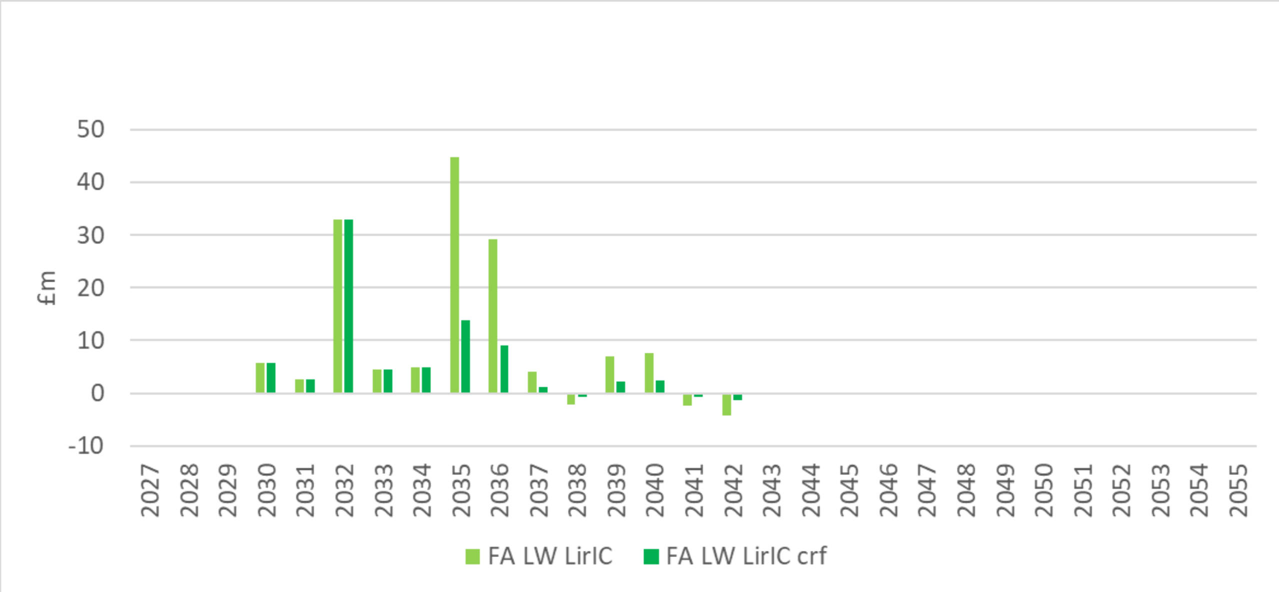
Figure 150: Additional annual constraint costs (undiscounted) due to LirIC for the Marginal Additional case.



In the Marginal Additional case, LirIC results in an increase in constraint costs of approximately £40m to £60m (undiscounted) in CT, LW and FS for the years 2031 to 2035. The results are significantly higher than the original (March 2024) results.

Annual constraint costs (discounted), without and with Constraint Reduction Factor

Figure 151: Additional annual constraint costs (discounted) due to LirIC for the First Additional case for Leading the Way, without and with Constraint Reduction Factor applied.



The above chart shows the additional constraint costs without and with the Constraint Reduction Factor (CRF) applied for the Leading the Way scenario for the First Additional case. The chart shows the impact of the CRF being applied from 2035 onwards. Note that the results for 2043 are not visible on the chart because the average of 2040, 2041 and 2042 is less than £1m without and with the CRF applied.

Figure 152: Additional annual constraint costs (discounted) due to LirIC for the First Additional case for Consumer Transformation, without and with Constraint Reduction Factor applied.

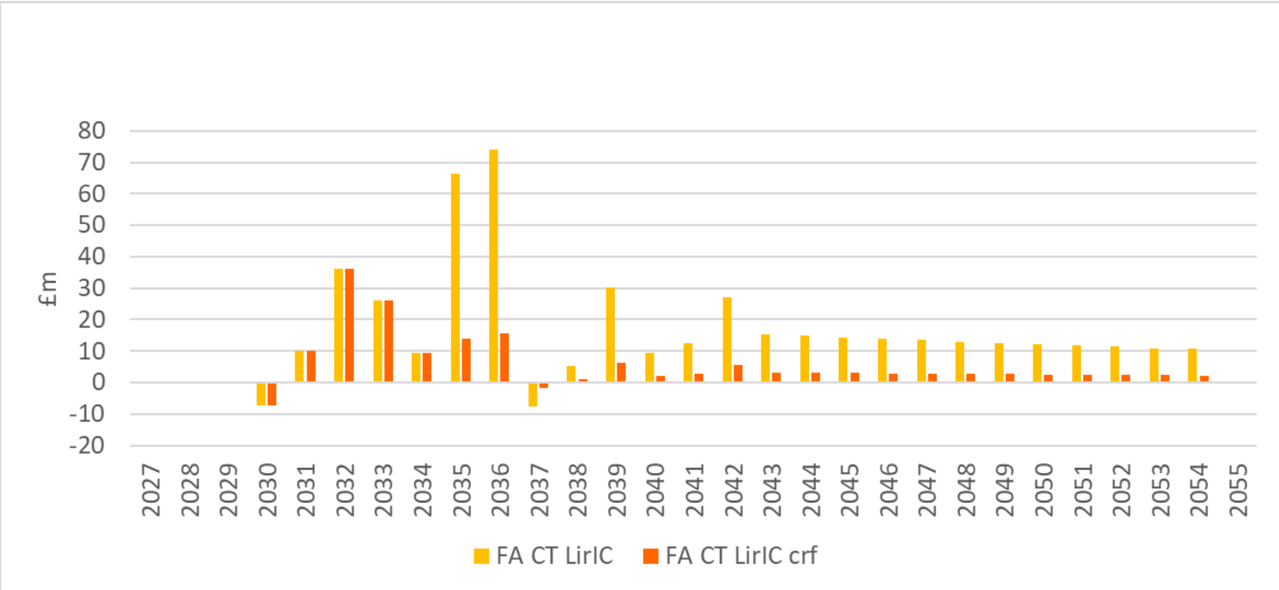
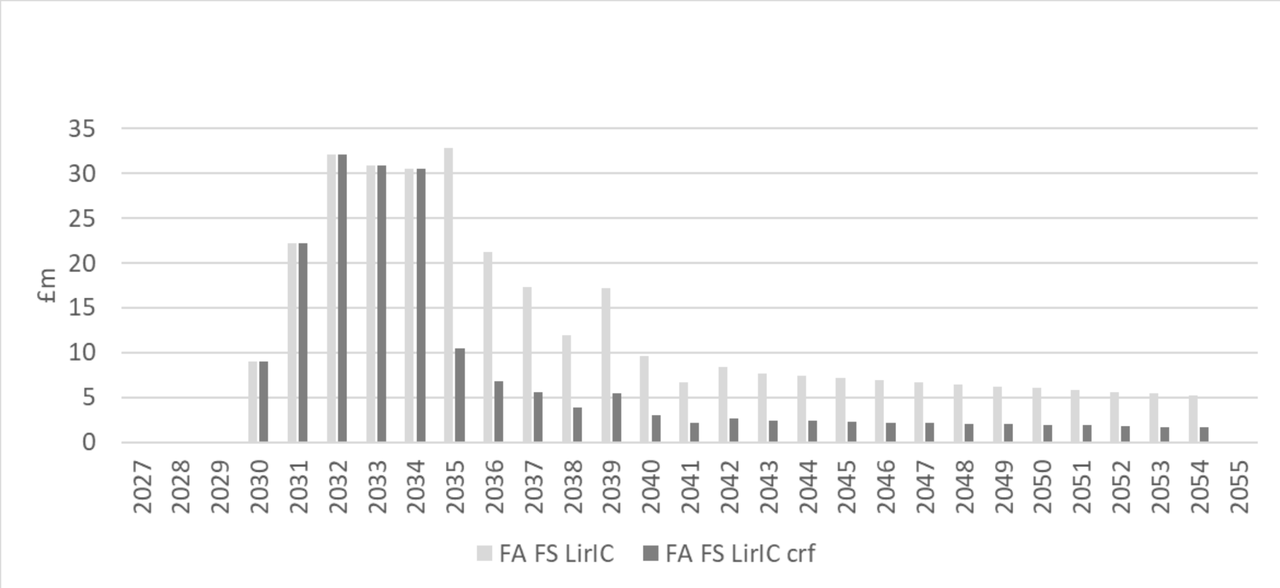
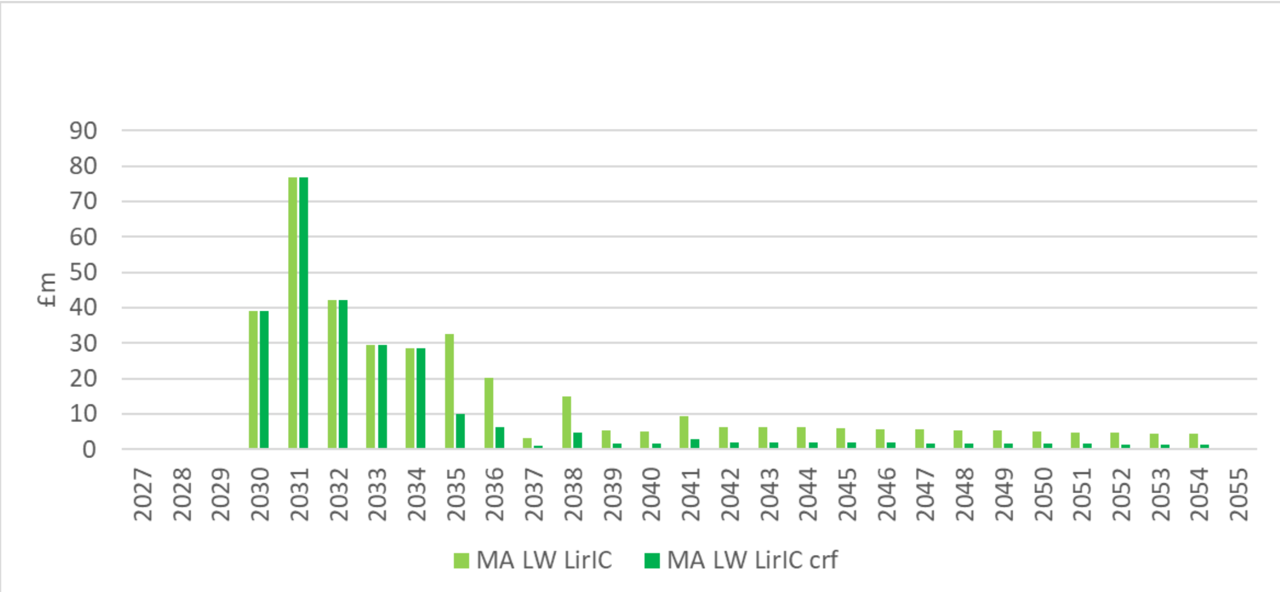


Figure 153: Additional annual constraint costs (discounted) due to LirIC for the First Additional case for Falling Short, without and with Constraint Reduction Factor applied.



The above chart shows the additional constraint costs without and with the Constraint Reduction Factor (CRF) applied. The chart shows the impact of the CRF being applied from 2035 onwards.

Figure 154: Additional annual constraint costs (discounted) due to LirIC for the Marginal Additional case for Leading the Way, without and with Constraint Reduction Factor applied.



The above chart shows the additional constraint costs without and with the Constraint Reduction Factor (CRF) applied for the Leading the Way scenario for the Marginal Additional case. The chart shows the impact of the CRF being applied from 2035 onwards.

Figure 155: Additional annual constraint costs (discounted) due to LirIC for the Marginal Additional case for Consumer Transformation, without and with Constraint Reduction Factor applied.

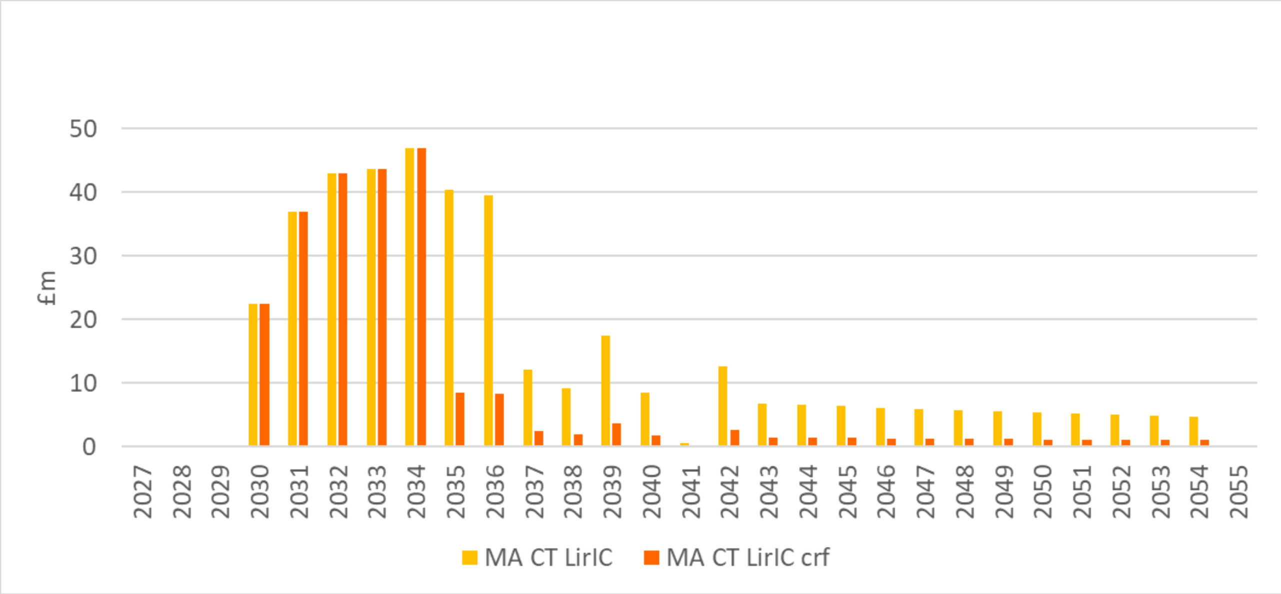
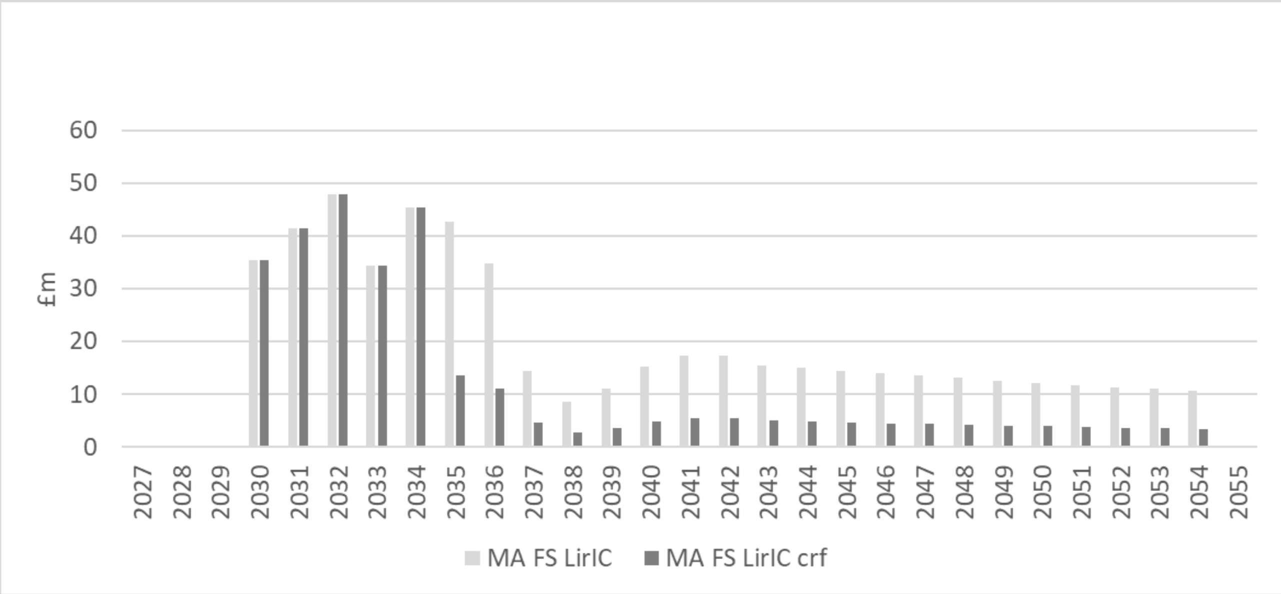
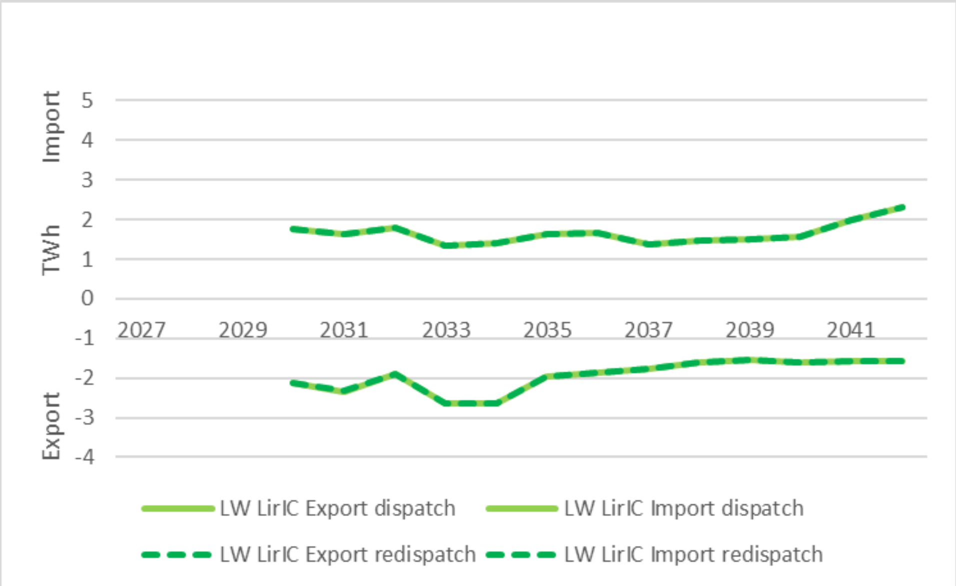


Figure 156: Additional annual constraint costs (discounted) due to LirIC for the Marginal Additional case for Falling Short, without and with Constraint Reduction Factor applied.



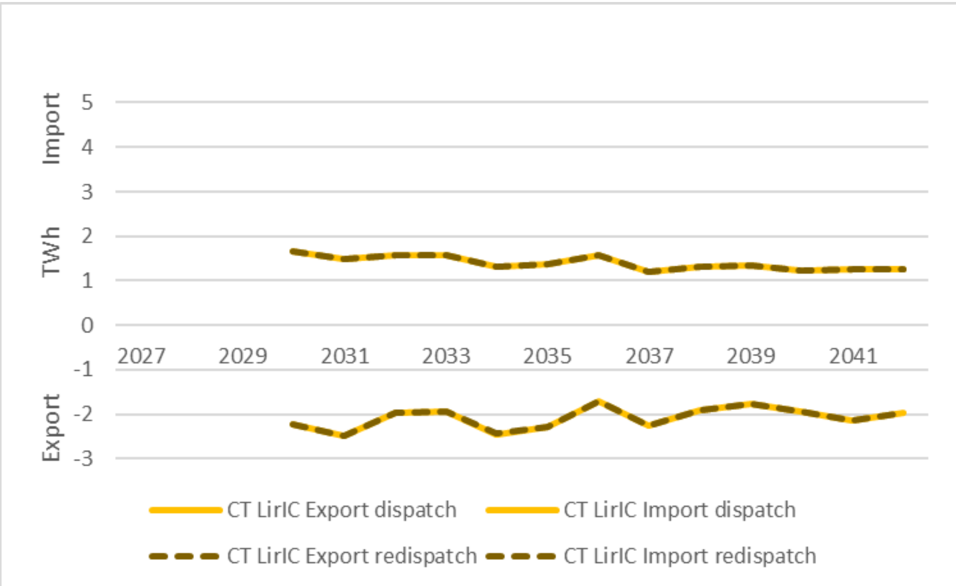
Annual import and export flows for dispatch and redispatch

Figure 157: Annual import and export flows for LirIC in the FA case for Leading the Way.



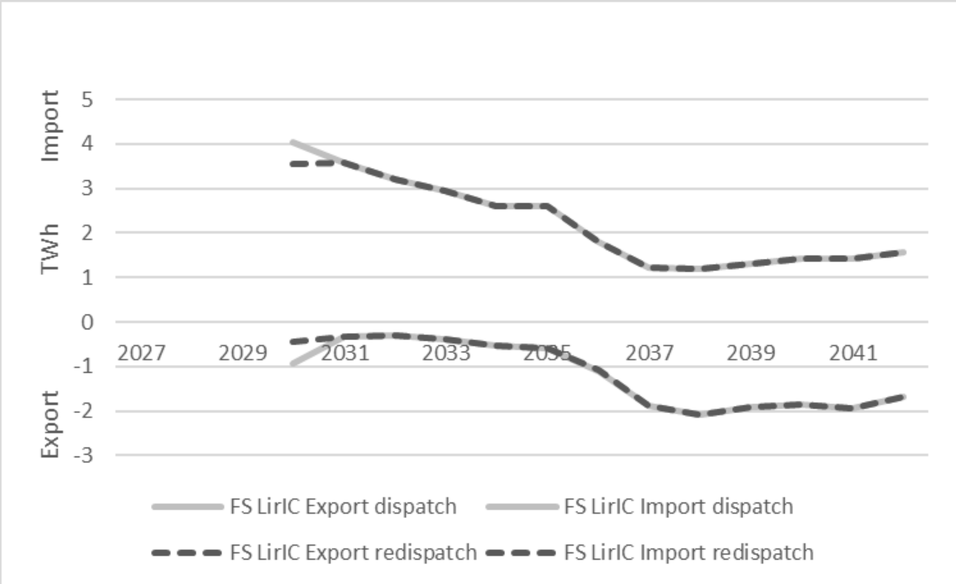
The above figure shows similar levels of exports and imports in the dispatch initially, then in the later years imports increase slightly and exports reduce. The redispatch shows the same levels of exports and imports as the dispatch. This is because the BID3 model is configured to model as accurately as possible the actual operation of the transmission system. Compared to the original (March 2024) results, imports are significantly higher and exports are significantly lower.

Figure 158: Annual import and export flows for LirIC in the FA case for Consumer Transformation.



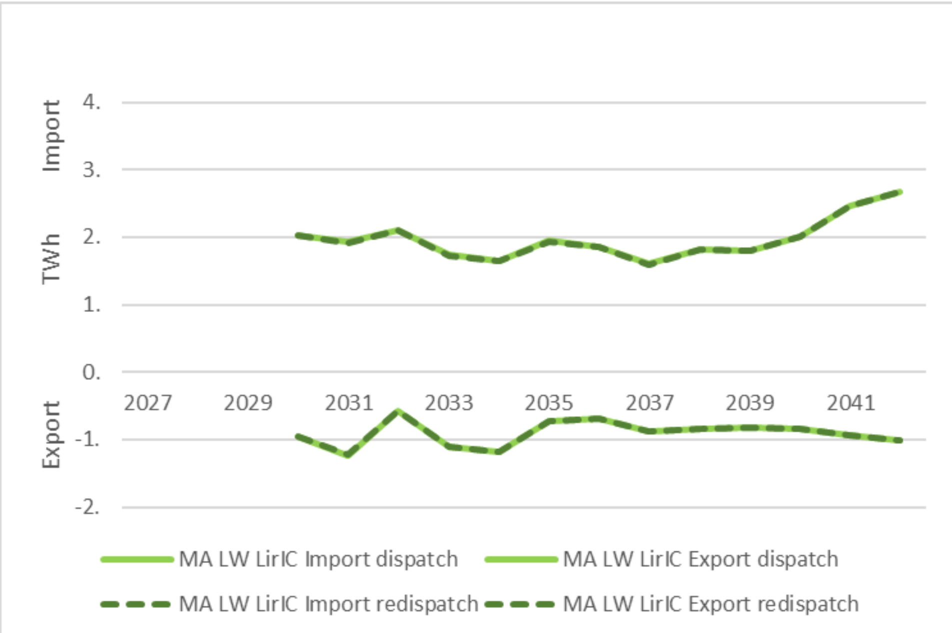
The above figure shows similar levels of exports and imports in the dispatch initially. The redispatch shows the same levels of exports and imports as the dispatch. This is because the BID3 model is configured to model as accurately as possible the actual operation of the transmission system. Compared to the original (March 2024) results, imports are significantly higher and exports are significantly lower.

Figure 159: Annual import and export flows for LirIC in the FA case for Falling Short.



The above figure shows that for the First Additional case LirIC has increasing levels of exports and reducing imports over the first half of the forecast period for Falling Short. Thereafter exports are relatively flat and imports rise slightly. The redispatch shows the same levels of exports and imports as the dispatch. This is because the BID3 model is configured to model as accurately as possible the actual operation of the transmission system. Compared to the original (March 2024) results, imports are significantly higher and exports are significantly lower.

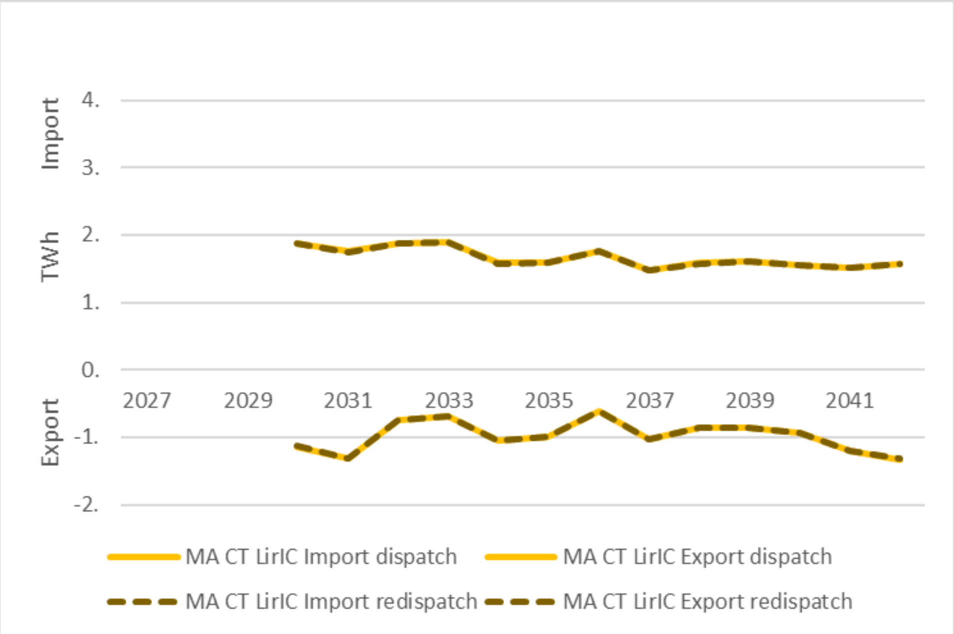
Figure 160: Annual import and export flows for LirIC in the MA case for Leading the Way.



The above figure shows for the dispatch high imports, and low exports. The redispatch shows the same levels of exports and imports as the dispatch. This is because the BID3 model is configured to model as accurately as possible the actual operation of the transmission system. Compared to the original (March 2024) results, imports are significantly higher and exports are significantly lower.

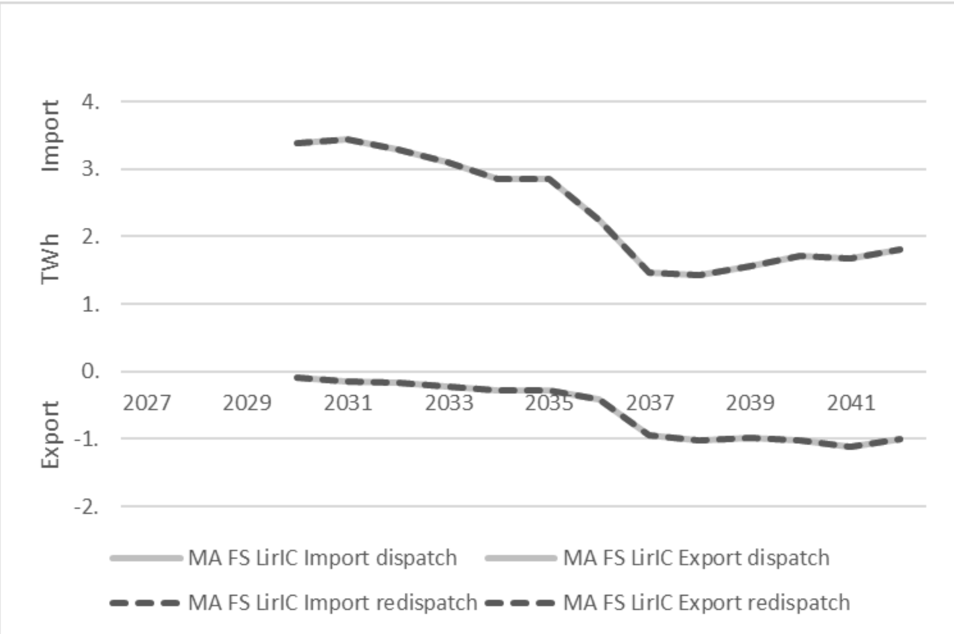
Public

Figure 161: Annual import and export flows for LirIC in the MA case for Consumer Transformation.



The above figure shows for the dispatch high imports, and low exports. The redispatch shows the same levels of exports and imports as the dispatch. This is because the BID3 model is configured to model as accurately as possible the actual operation of the transmission system. Compared to the original (March 2024) results, imports are significantly higher and exports are significantly lower.

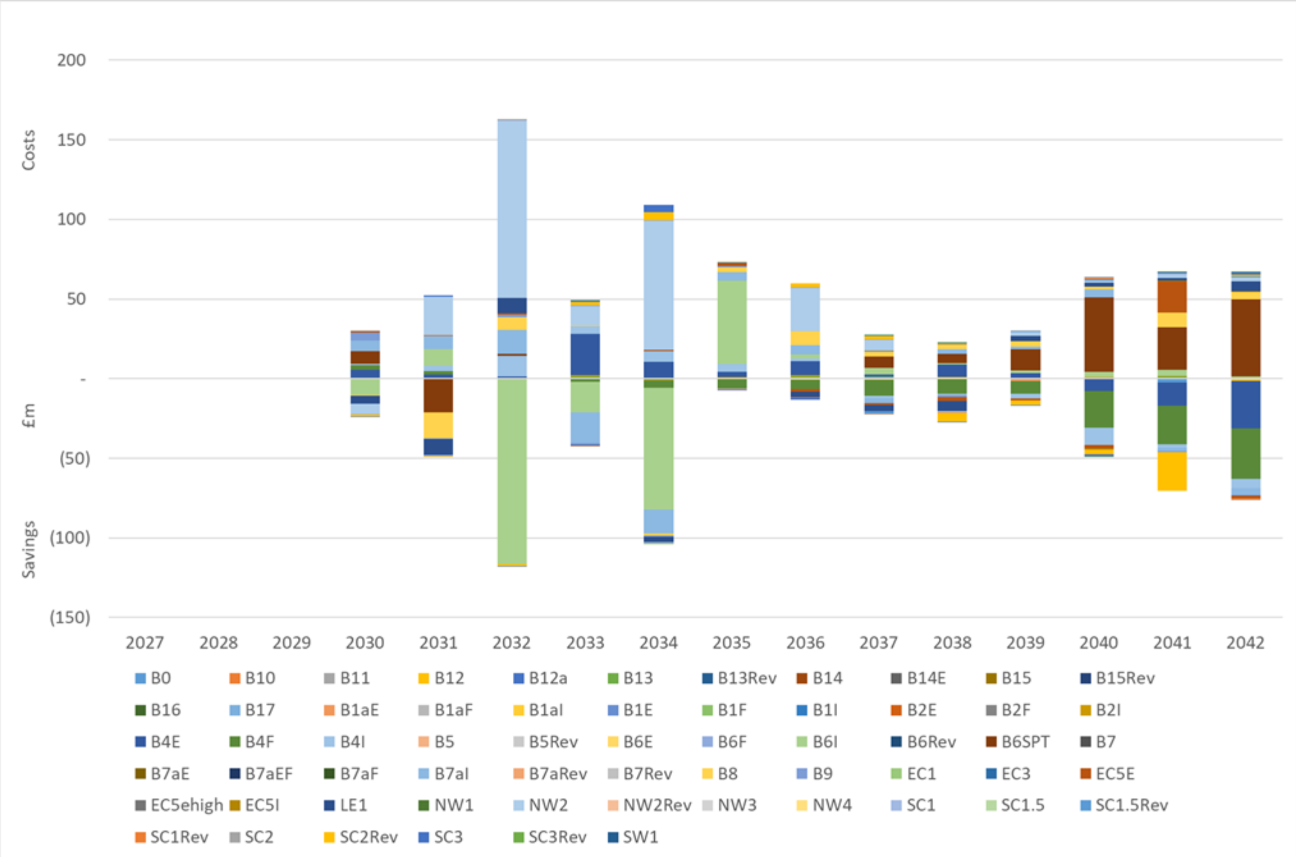
Figure 162: Annual import and export flows for LirIC in the MA case for Falling Short.



The above figure shows for the dispatch high imports, and very low exports. The redispatch shows the same levels of exports and imports as the dispatch. This is because the BID3 model is configured to model as accurately as possible the actual operation of the transmission system. Compared to the original (March 2024) results, imports are significantly higher and exports are significantly lower.

Change in constraint costs by boundary

Figure 163: Change in constraint costs by boundary for LirIC for the First Additional case for Leading the Way.



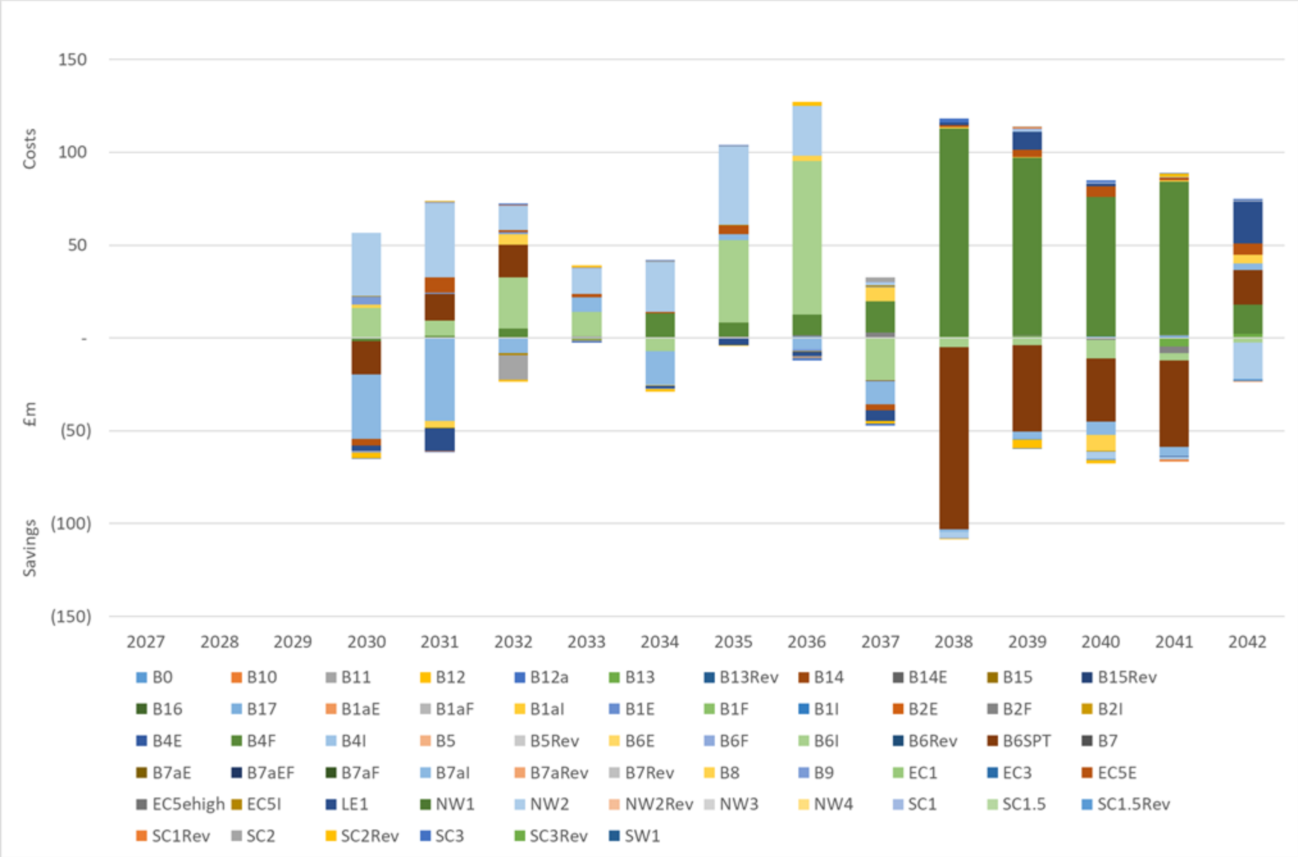
The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary LirIC for the First Additional case for the Leading the Way scenario. Each different colour represents the change in constraint costs for a particular boundary. It is important to note that the chart shows changes in constraint costs by boundary, i.e. the difference between constraint costs when the project is included and when the project is excluded.

The figure shows that LirIC increases constraint costs on certain northern boundaries but also reduces constraint costs on others. Whether the impact is an increase in constraint costs or a reduction in constraint costs for a particular boundary, changes from year to year. The size of change in constraint costs by boundary can also vary significantly from year to year. This is shown clearly in the years 2032 to 2033. The figure also shows that the specific boundaries that have the greatest impact on the total change in constraint costs can vary from year to year. These factors are a result of the changes in demand, supply and network capability over time.

In general, LirIC increases constraint costs on several northern boundaries and one Welsh boundary but relieves congestion on the northern boundaries in different years. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis, constraint costs are higher on the Welsh boundary NW2 but significantly lower on one northern boundary. Overall, the additional constraint costs for LirIC are reduced compared to the original analysis.

Figure 164: Change in constraint costs by boundary for LirIC for the First Additional case for Consumer Transformation.

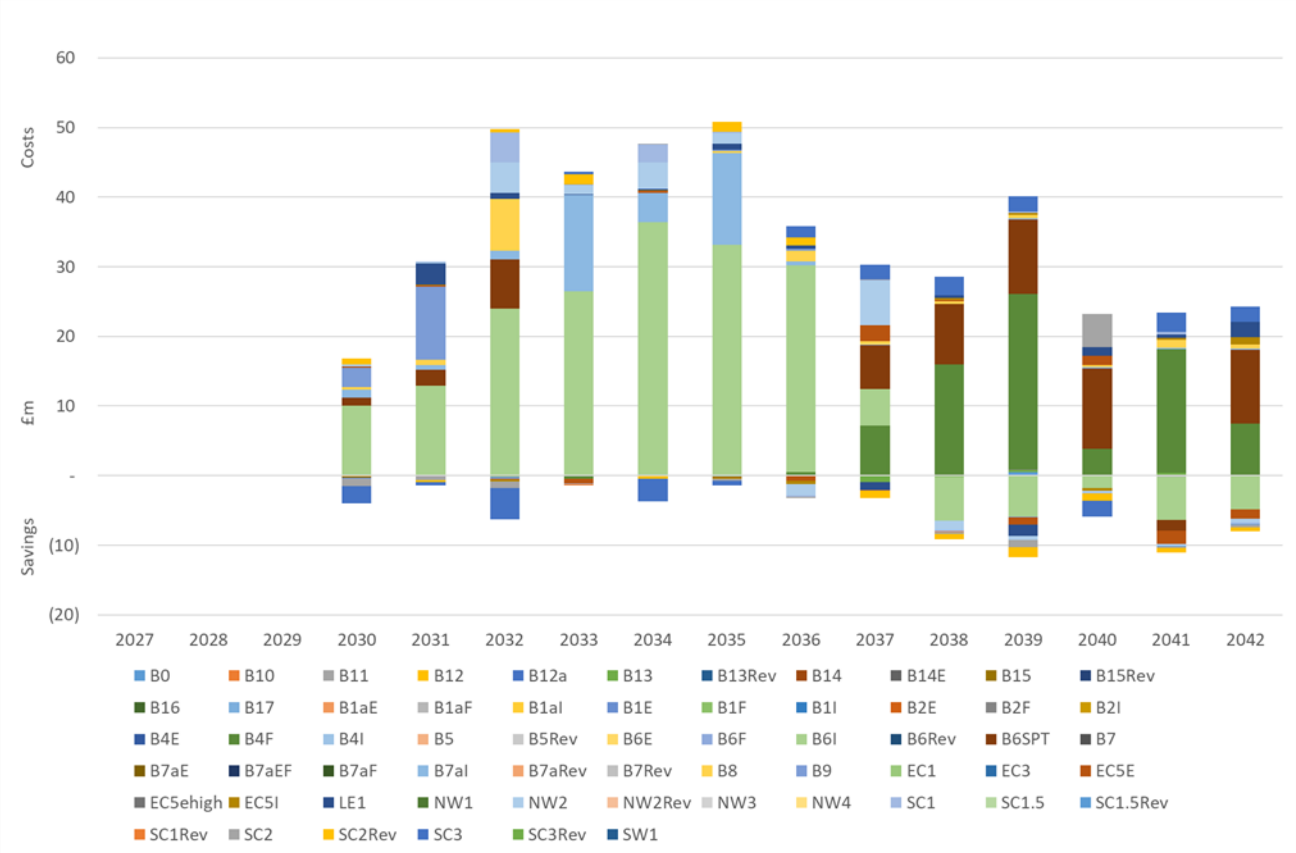


The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for LirIC for the First Additional case for the Consumer Transformation scenario.

In general, LirIC increases constraint costs on several northern and one Welsh boundary, but also relieves congestion on northern boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis constraint costs are higher on several northern and one Welsh boundary.

Figure 165: Change in constraint costs by boundary for LirIC for the First Additional case for Falling Short.

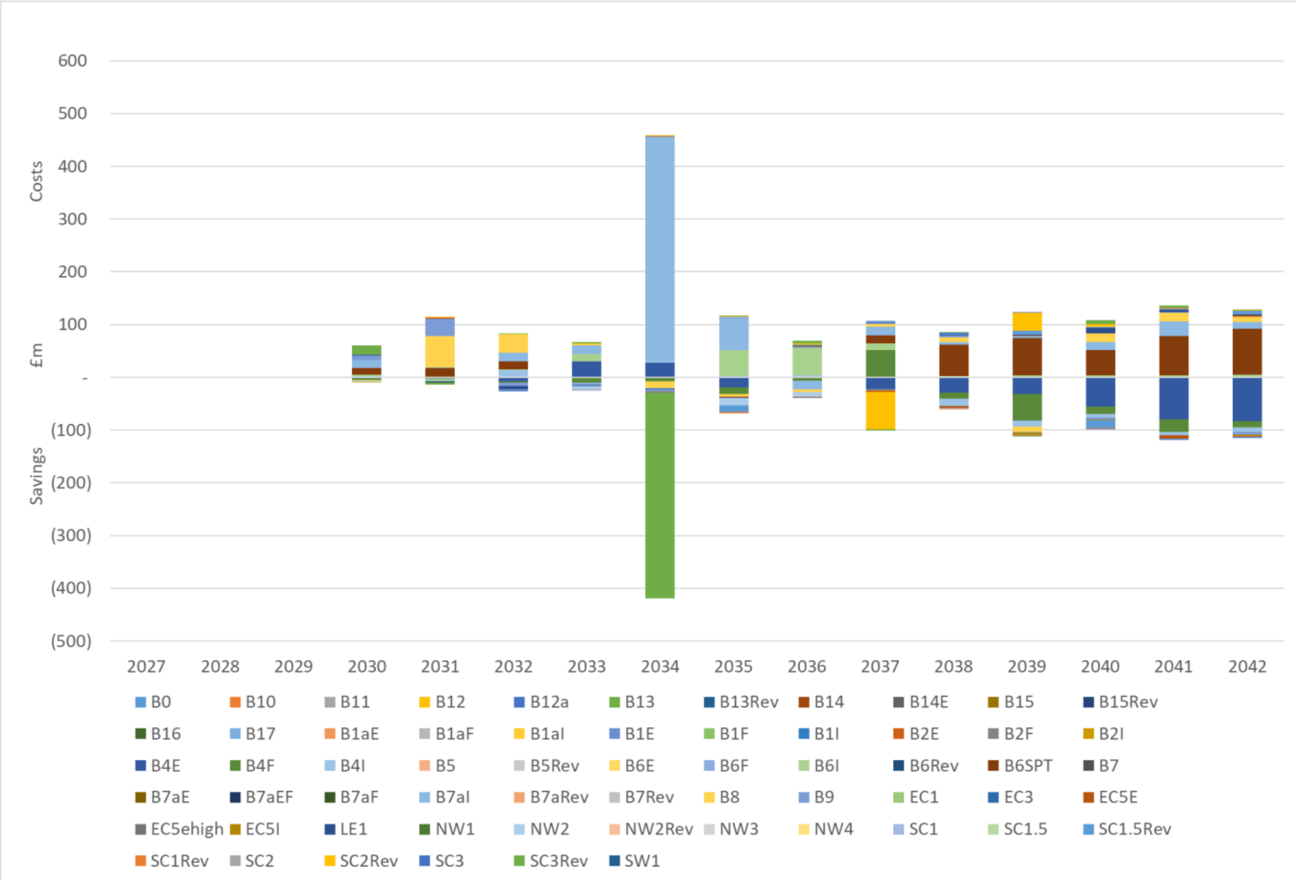


The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for LirIC for the First Additional case for the Falling Short scenario.

In general, LirIC increases constraint costs on several northern boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis, constraint costs are higher on several northern boundaries.

Figure 166: Change in constraint costs by boundary for LirIC for the Marginal Additional case for Leading the Way.



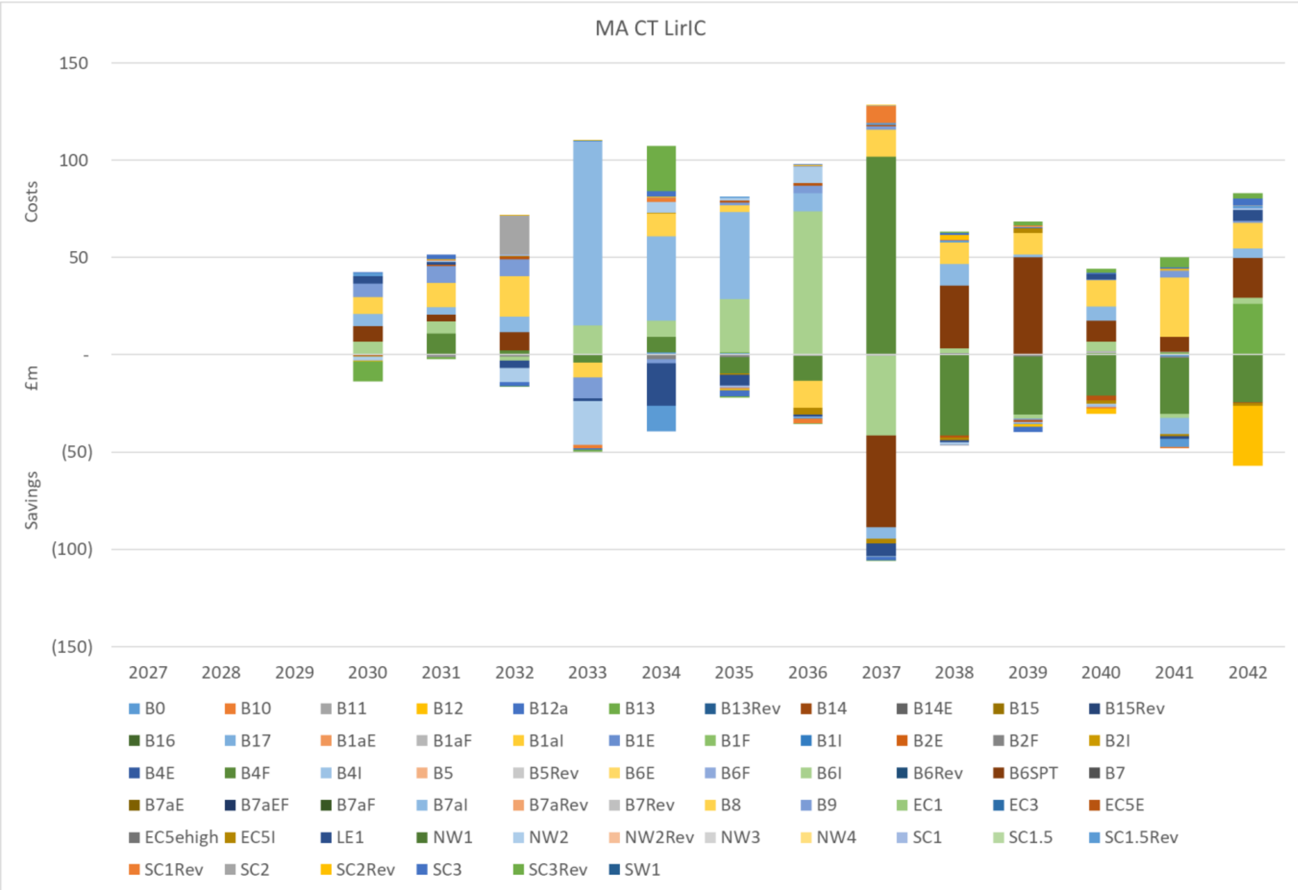
The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for LirIC for the Marginal Additional case for the Leading the Way scenario.

In general, LirIC increases constraint costs on several northern and midland boundaries but relieves congestion on various boundaries including one southern boundary for one year in particular. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

LirIC relieves congestion on one particular southern boundary in 2034. The saving only occurs for a single year suggesting the combination of supply, demand and boundary capabilities that enable such a significant saving across one boundary when LirIC is included only exist for that year. That is in later years, supply and demand patterns and boundary capabilities will have evolved such that the model is no longer able to produce the lowest total cost solution by significantly reducing constraint costs across that particular boundary when LirIC is included.

Compared to the original (March 2024) analysis, constraint costs are higher on several northern and midland boundaries. There are savings on several southern boundaries, but savings on various northern boundaries in the original analysis are significantly reduced.

Figure 167: Change in constraint costs by boundary for LirIC for the Marginal Additional case for Consumer Transformation.



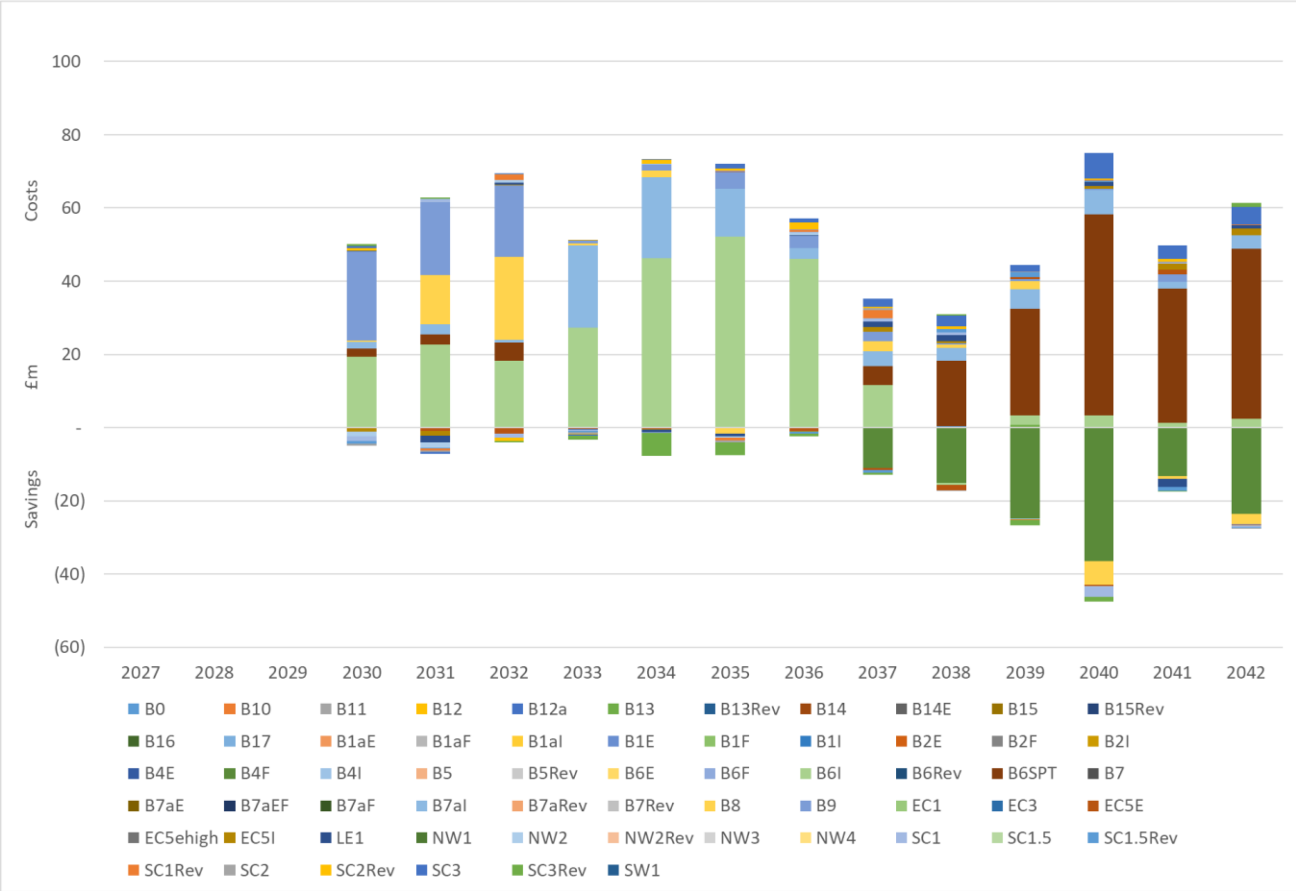
The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for LirIC for the Marginal Additional case for the Consumer Transformation scenario.

In general, LirIC increases constraint costs on several northern and midland boundaries, but also relieves congestion on various northern boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis constraint costs are higher on several northern boundaries, but savings on various northern boundaries in the original analysis are significantly reduced in the latest modelling.

In summary the changes to Irish demand and generation lead to higher imports across LirIC leading to less congestion on the B4 boundary but increased congestion on other northern boundaries.

Figure 168: Change in constraint costs by boundary for LirIC for the Marginal Additional case for Falling Short.



The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for LirIC for the Marginal Additional case for the Falling Short scenario.

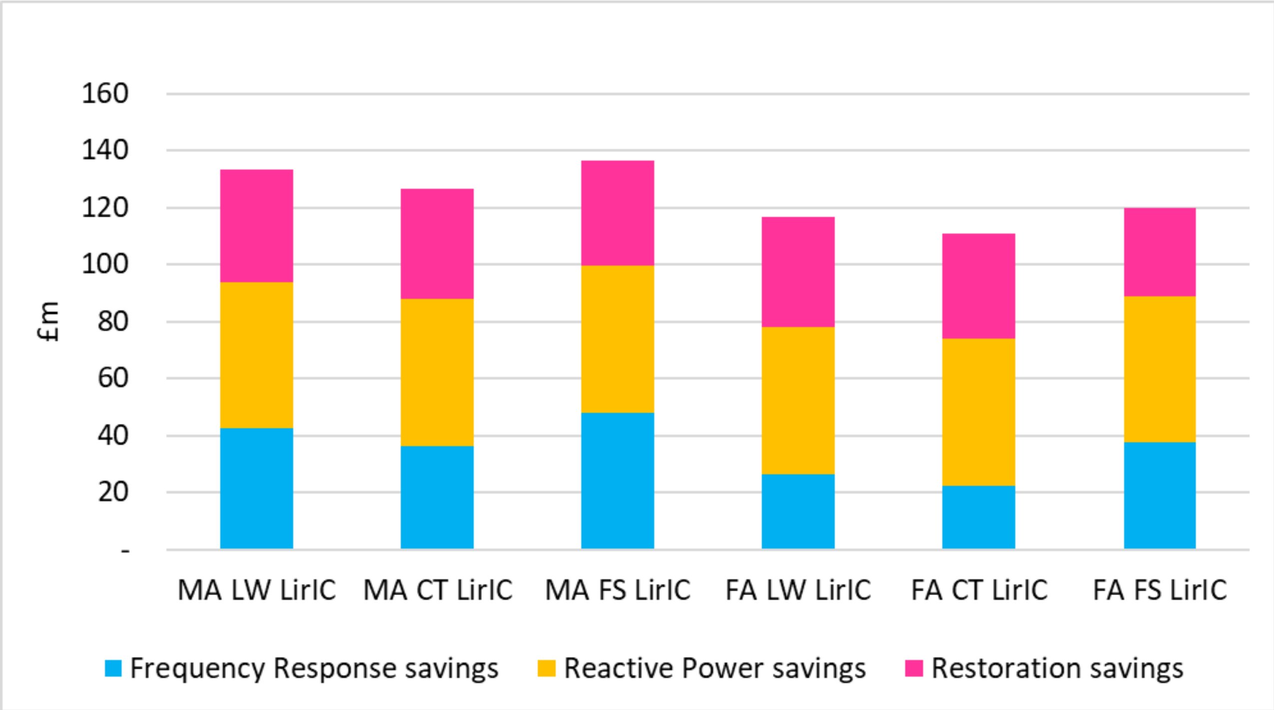
In general, LirIC increases constraint costs on several northern boundaries, but relieves congestion on another certain northern boundary in the later years. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis constraint costs are higher on several northern boundaries.

PV system operation

Note: The modelling and analysis for system operation is the same as that within the March 2024 report. It was not necessary to repeat the work because the change in modelling assumptions would not produce a material change in the results.

Figure 169: PV potential system operability savings for LirIC, Present Value 25-year, real 2022, £m.

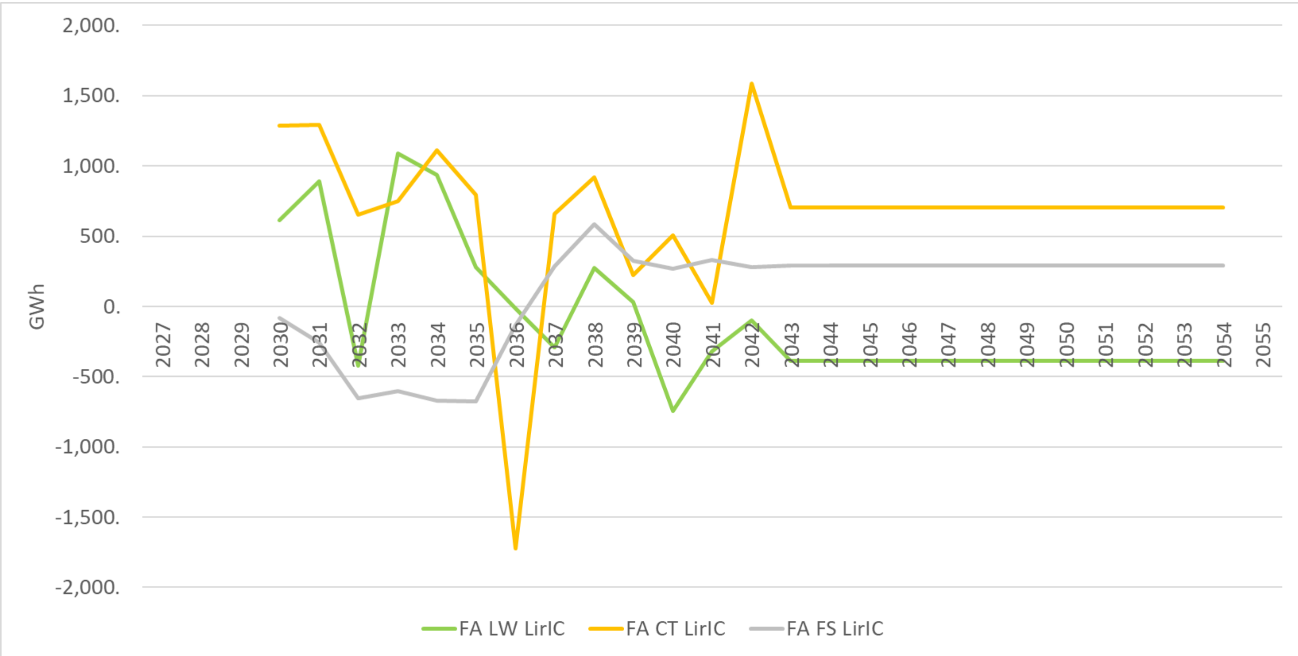


The above figure shows the potential savings for frequency response, reactive power and restoration services in present value (25-year, 2022 £m) for LirIC for Leading the Way, Consumer Transformation and Falling Short for both the Marginal Additional and First Additional cases. There is considerable uncertainty around forecasting potential system operability benefits over a 25-year time horizon, but the figure shows that there is potentially significant savings in frequency response, reactive power and restoration services.

There is little variation across the three scenarios and also across the First Additional and Marginal Additional cases. This is because the potential system operability savings from the services provided by LirIC are less sensitive to flows across the interconnector, whereas the constraint cost impact is highly dependent on the scale and direction of flows across the project.

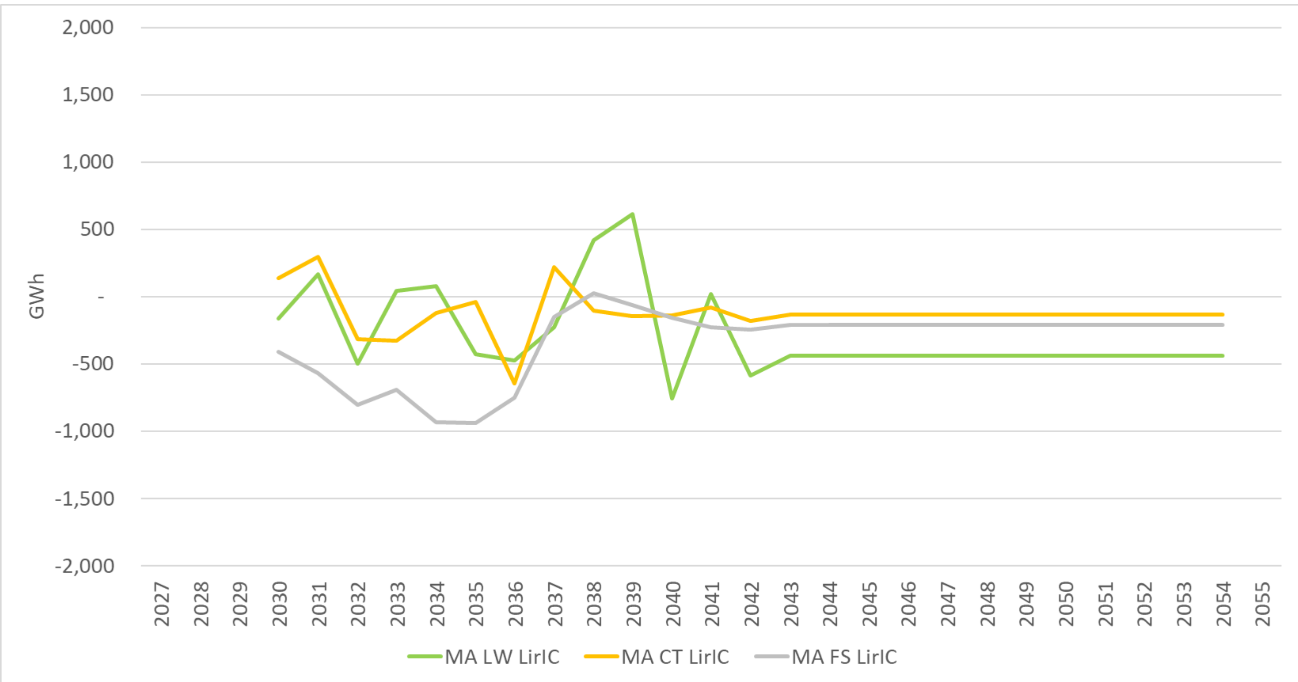
RES curtailment avoided

Figure 170: Annual RES curtailment avoided for LirIC for the First Additional case.



The above figure shows the renewable energy supply (RES) curtailment avoided on an annual basis for Leading the Way, Consumer Transformation and Falling Short for the First Additional case. Note that beyond 2042, the results are an average of the years 2040, 2041 and 2042, as our detailed modelling with FES22 only extends out to 2042. The figure shows that the level of annual RES curtailment avoided when LirIC is included is approximately between -1TWh and 1TWh, which equates to approximately a 2.7GWh per day decrease or increase in RES curtailment avoided respectively.

Figure 171: Annual RES curtailment avoided for LirIC for the Marginal Additional case.



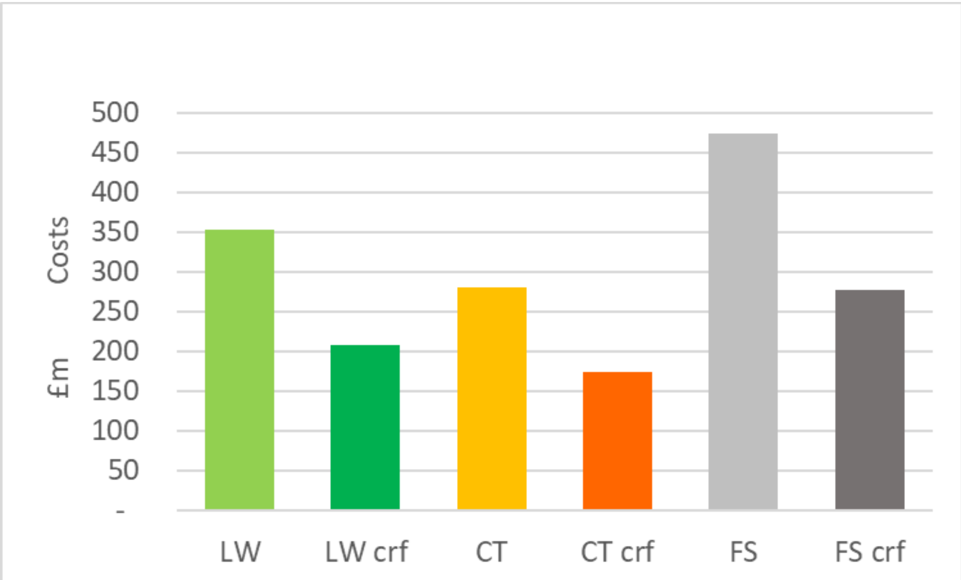
The above figure shows the renewable energy supply (RES) curtailment avoided on an annual basis for Leading the Way, Consumer Transformation and Falling Short for the Marginal Additional case. Note that beyond 2042, the results are an average of the years 2040, 2041 and 2042, as our detailed modelling with FES22 only extends out to 2042. The figure shows that for many of the years in all of the scenarios, the inclusion of LiriC results in a negative RES curtailment avoided result, that is an increase in RES curtailment. The figure shows that the level of annual RES curtailment avoided when LirIC is included is approximately between -1TWh and 0.5TWh, which equates to approximately a 2.7GWh per day decrease or 1.4GWh increase in RES curtailment avoided respectively.

15. MaresConnect

MaresConnect is a W3 interconnector project. It has a capacity of 0.75GW and connects to Ireland.

PV constraint costs

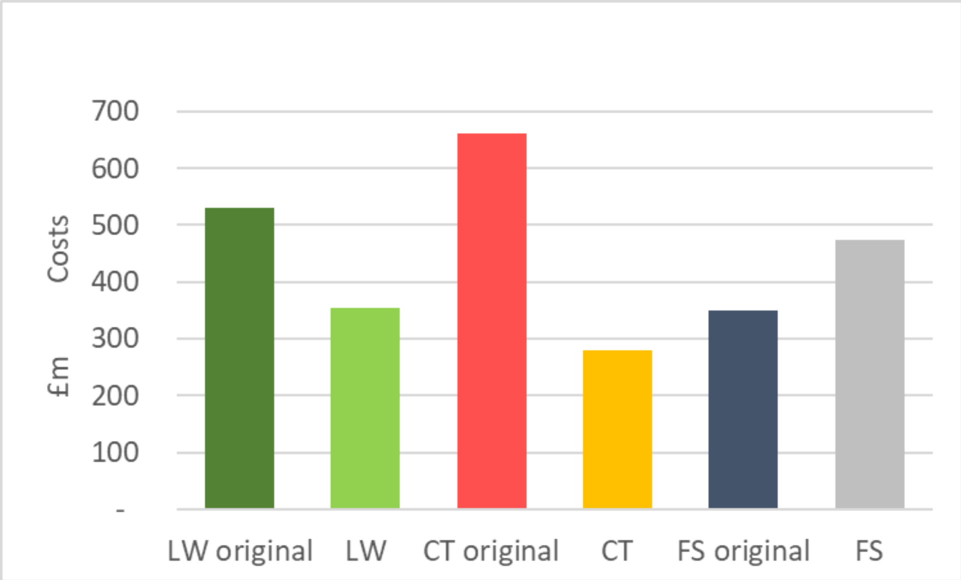
Figure 172: PV additional constraint costs due to MaresConnect for the First Additional case, Present Value 25-year, real 2022, £m, without and with Constraint Reduction Factor applied.



The above figure shows the additional constraint costs with the inclusion of MaresConnect for the FA case. Without the Constraint Reduction Factor applied, in the Leading the Way scenario (LW) constraint costs are increased by £0.35bn, in Consumer Transformation (CT) by £0.28bn and in the Falling Short (FS) scenario by £0.47bn.

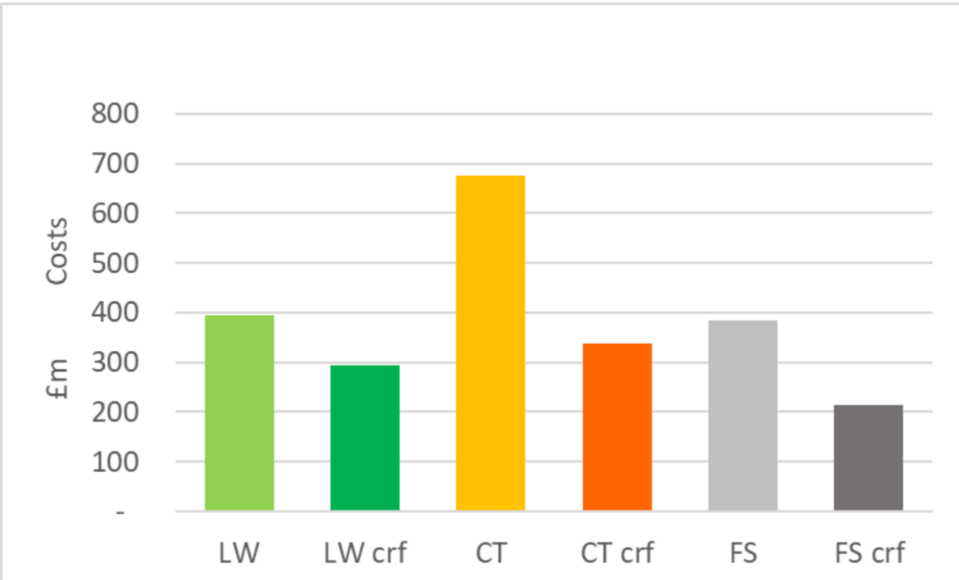
With the Constraint Reduction Factor applied, in the Leading the Way scenario (LW) constraint costs are increased by £0.21bn, in Consumer Transformation (CT) by £0.17bn and in the Falling Short (FS) scenario by £0.28bn.

Figure 173: PV additional constraint costs due to MaresConnect for the First Additional case, Present Value 25-year, real 2022, £m, for the original analysis (March 2024) and for Nautilus at Grain with 1.4GW link and Irish demand and generation from TYNDP.



The above figure shows that the changes made to the scenarios, that is the reduction in the capacity of the link connecting the Nautilus offshore platform to Belgium from 3.5GW to 1.4GW and the change in Irish demand and generation to reflect final TYNDP data results in a significant decrease in constraint costs in LW and CT scenarios and an increase in FS.

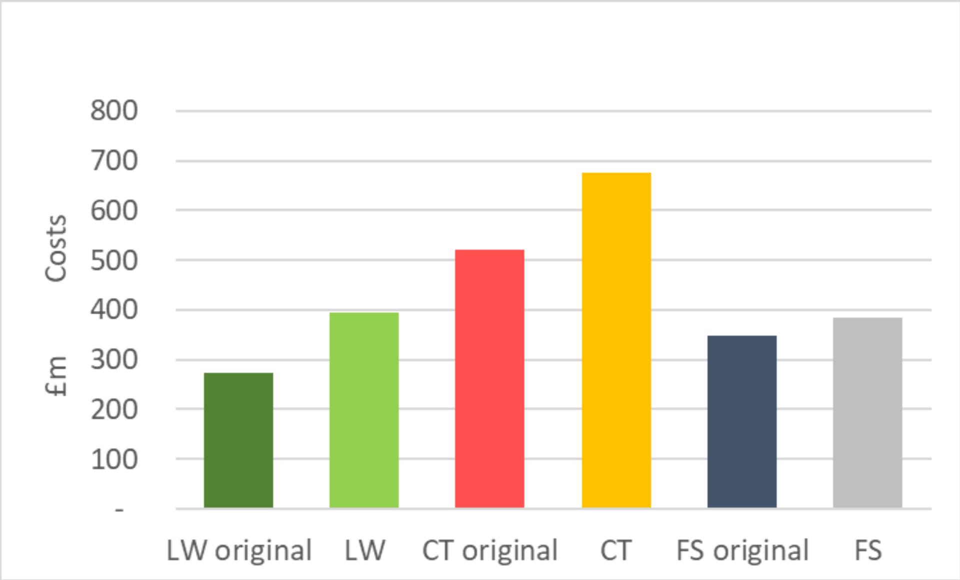
Figure 174: PV additional constraint costs due to MaresConnect for the Marginal Additional case, Present Value 25-year, real 2022, £m, without and with Constraint Reduction Factor applied.



The above figure shows the additional constraint costs with the inclusion of MaresConnect for the MA case. Without the Constraint Reduction Factor applied, in the Leading the Way scenario (LW) constraint costs are increased by £0.4bn, in Consumer Transformation (CT) by £0.68bn and in the Falling Short (FS) scenario by £0.38bn.

With the Constraint Reduction Factor applied, in the Leading the Way scenario (LW) constraint costs are increased by £0.3bn, in Consumer Transformation (CT) by £0.34bn and in the Falling Short (FS) scenario by £0.22bn.

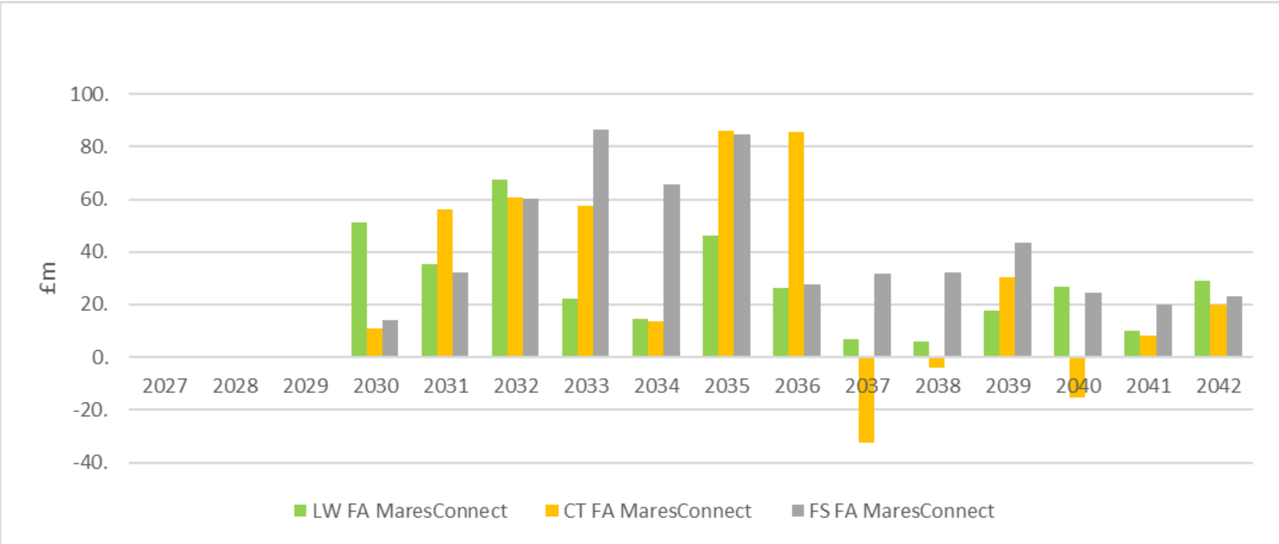
Figure 175: PV additional constraint costs due to MaresConnect for the Marginal Additional case, Present Value 25-year, real 2022, £m, for the original analysis (March 2024) and for Nautilus at Grain with 1.4GW link and Irish demand and generation from TYNDP.



The above figure shows that the changes made to the scenarios, that is the reduction in the capacity of the link connecting the Nautilus offshore platform to Belgium from 3.5GW to 1.4GW and the change in Irish demand and generation to reflect final TYNDP data results in a significant increase in constraint costs in the LW and CT scenarios and a smaller increase in FS.

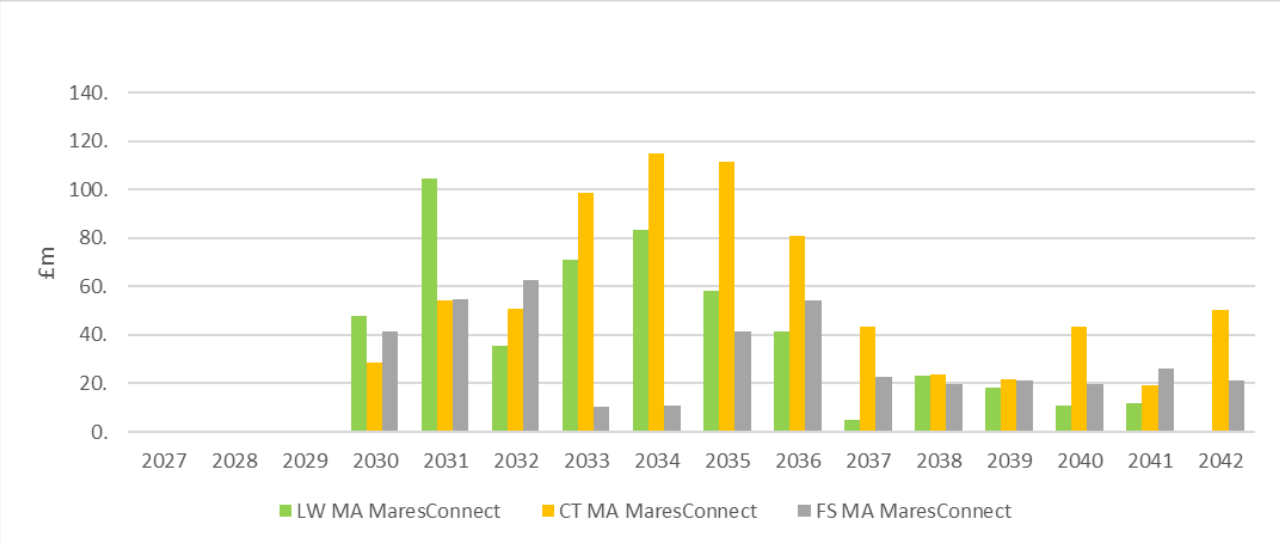
Annual constraint costs (undiscounted)

Figure 176: Additional annual constraint costs (undiscounted) due to MaresConnect for the First Additional case.



The above figure shows that MaresConnect results in an increase in constraint costs of approximately £10m to £80m (undiscounted) in all three scenarios for the years 2030 to 2036. The results are lower than the original (March 2024) results for LW and CT, but higher for CT.

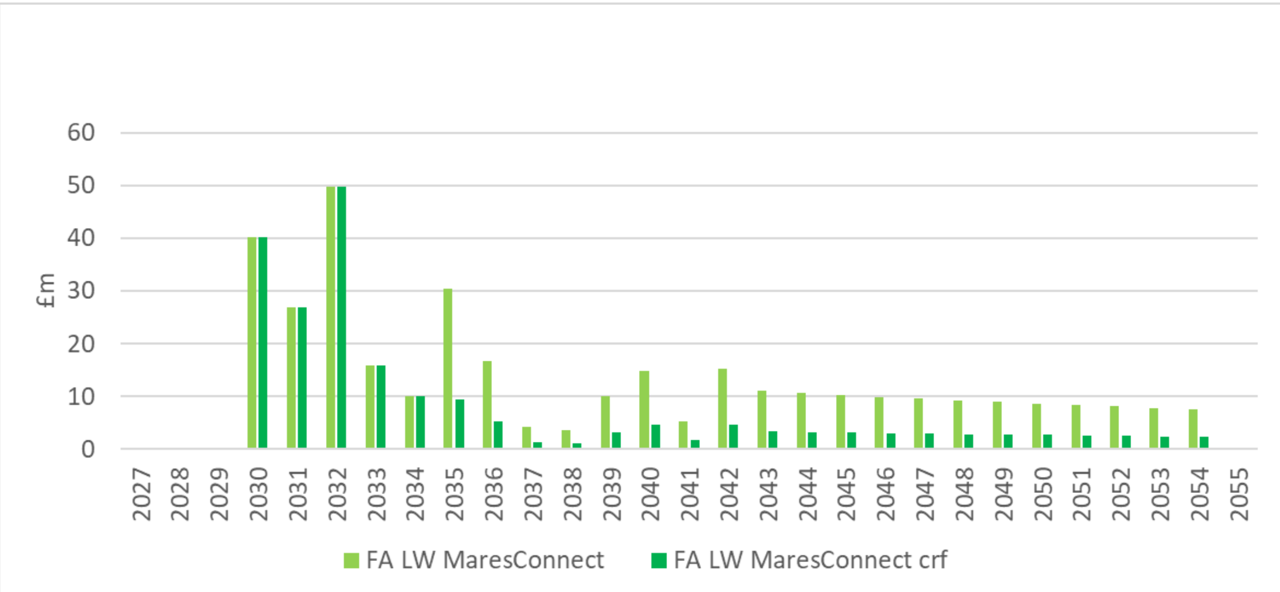
Figure 177: Additional annual constraint costs (undiscounted) due to MaresConnect for the Marginal Additional case.



In the Marginal Additional case, MaresConnect results in an increase in constraint costs of approximately £20m to £100m (undiscounted) in CT and LW for the years 2030 to 2036. FS shows much lower constraint savings for the years 2033 to 2034. The results are significantly higher than the original (March 2024) results for LW and CT and slightly higher for FS.

Annual constraint costs (discounted), without and with Constraint Reduction Factor

Figure 178: Additional annual constraint costs (discounted) due to MaresConnect for the First Additional case for Leading the Way, without and with Constraint Reduction Factor applied.



The above chart shows the additional constraint costs without and with the Constraint Reduction Factor (CRF) applied for the Leading the Way scenario for the First Additional case. The chart shows the impact of the CRF being applied from 2035 onwards.

Figure 179: Additional annual constraint costs (discounted) due to MaresConnect for the First Additional case for Consumer Transformation, without and with Constraint Reduction Factor applied.

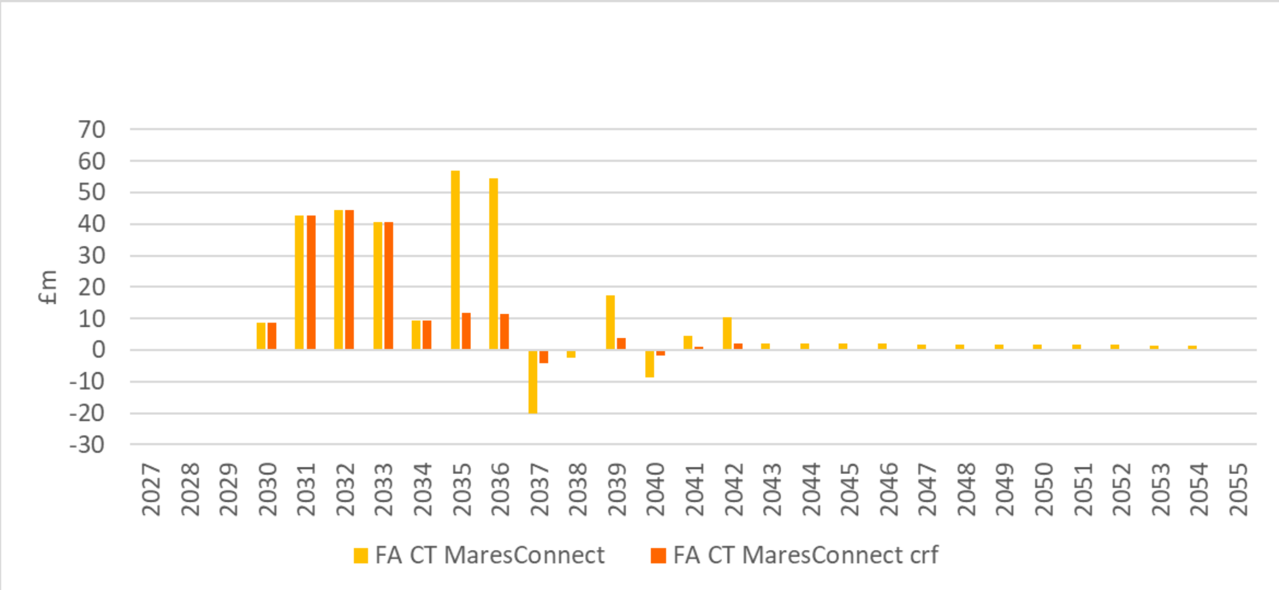
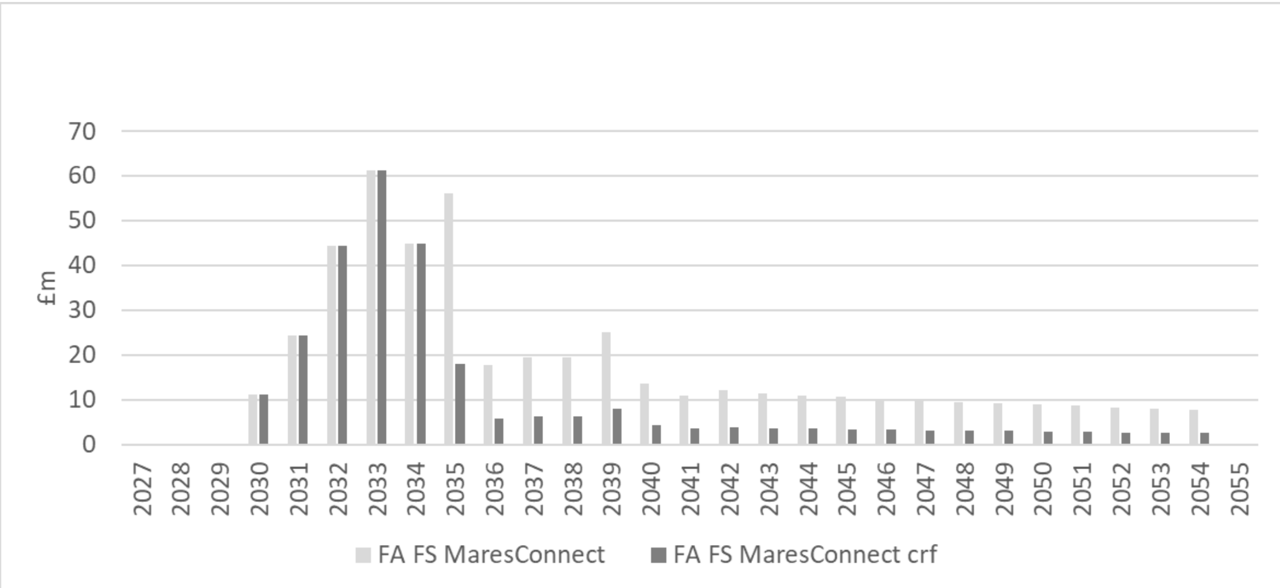
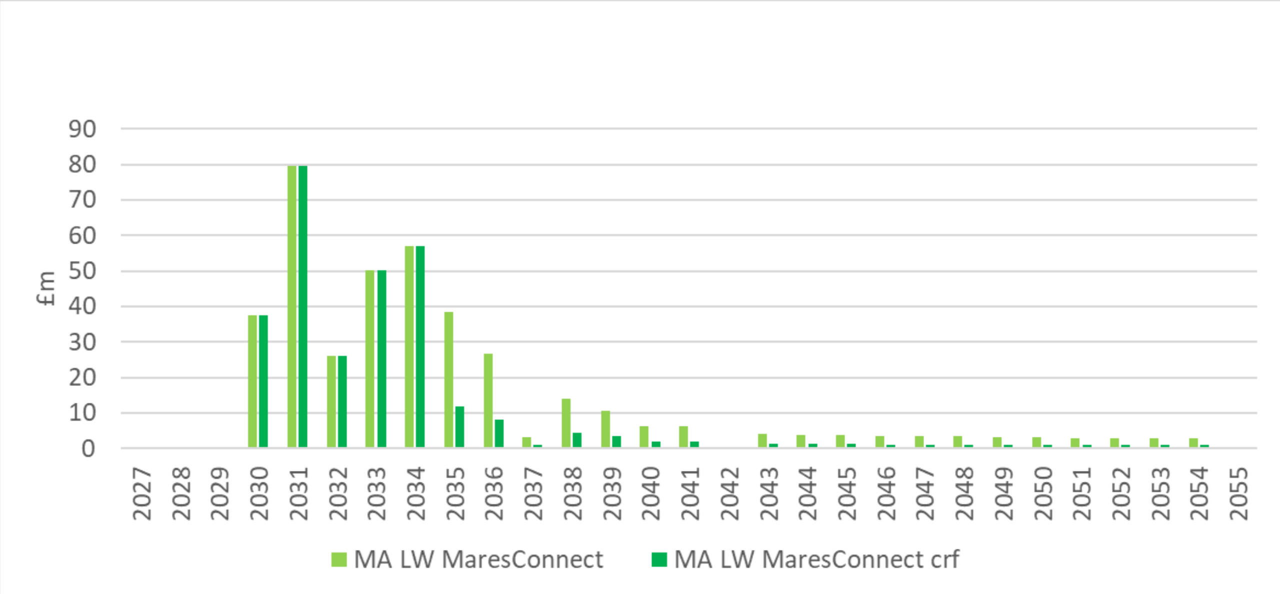


Figure 180: Additional annual constraint costs (discounted) due to MaresConnect for the First Additional case for Falling Short, without and with Constraint Reduction Factor applied.



The above chart shows the additional constraint costs without and with the Constraint Reduction Factor (CRF) applied. The chart shows the impact of the CRF being applied from 2035 onwards.

Figure 181: Additional annual constraint costs (discounted) due to MaresConnect for the Marginal Additional case for Leading the Way, without and with Constraint Reduction Factor applied.



The above chart shows the additional constraint costs without and with the Constraint Reduction Factor (CRF) applied for the Leading the Way scenario for the Marginal Additional case. The chart shows the impact of the CRF being applied from 2035 onwards.

Figure 182: Additional annual constraint costs (discounted) due to MaresConnect for the Marginal Additional case for Consumer Transformation, without and with Constraint Reduction Factor applied.

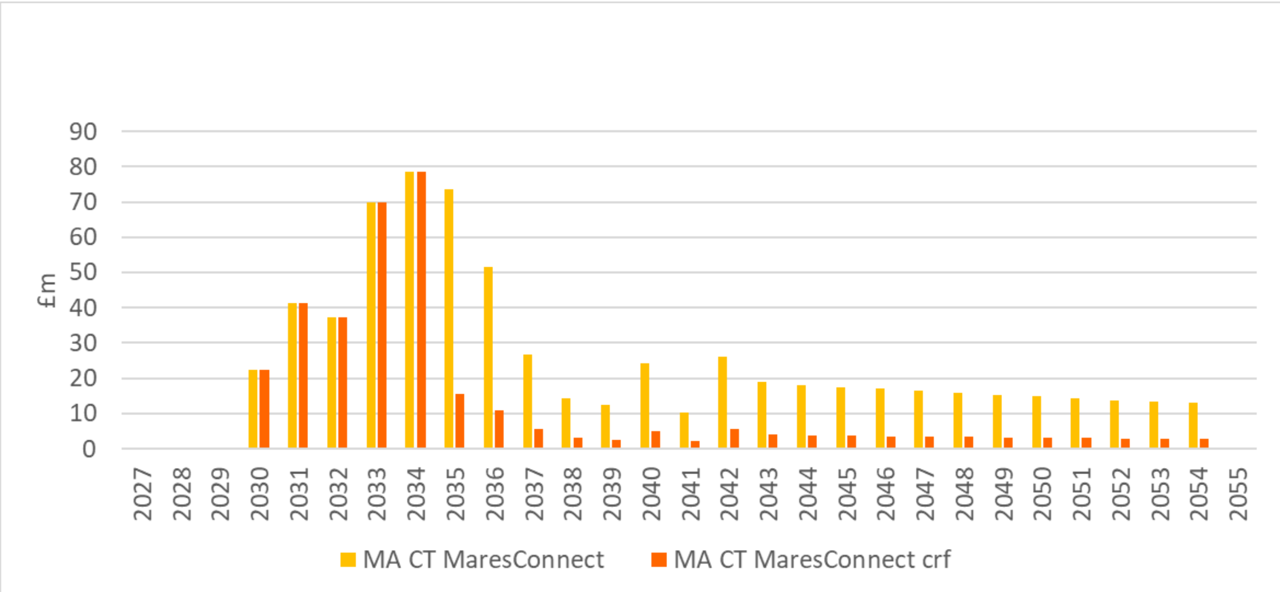
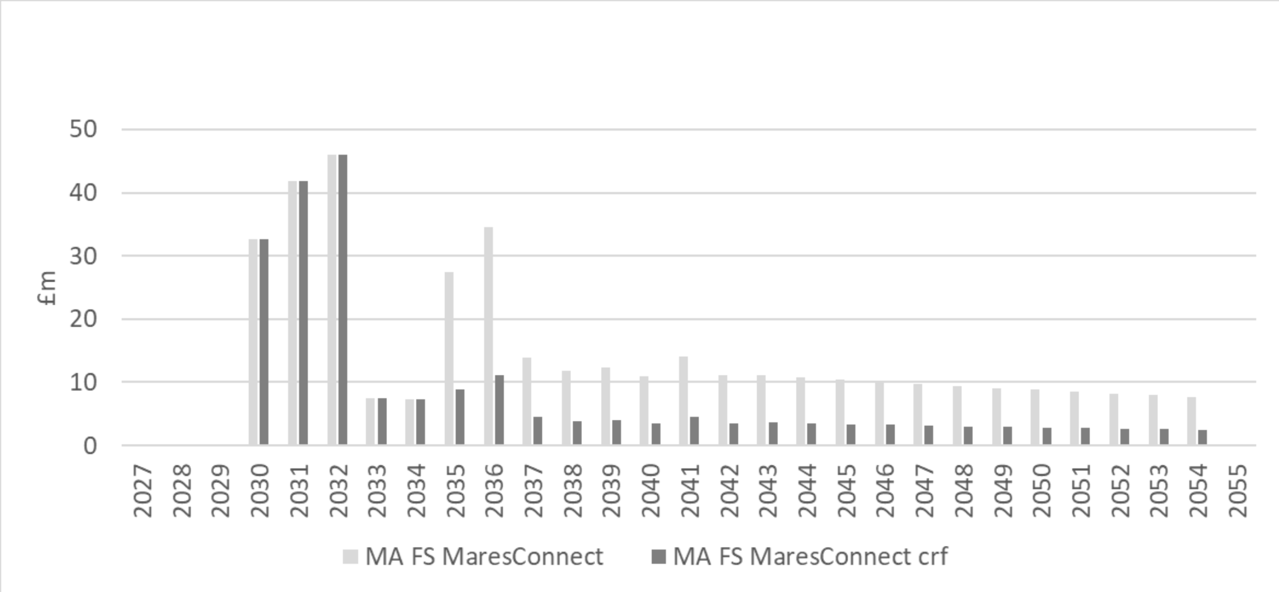
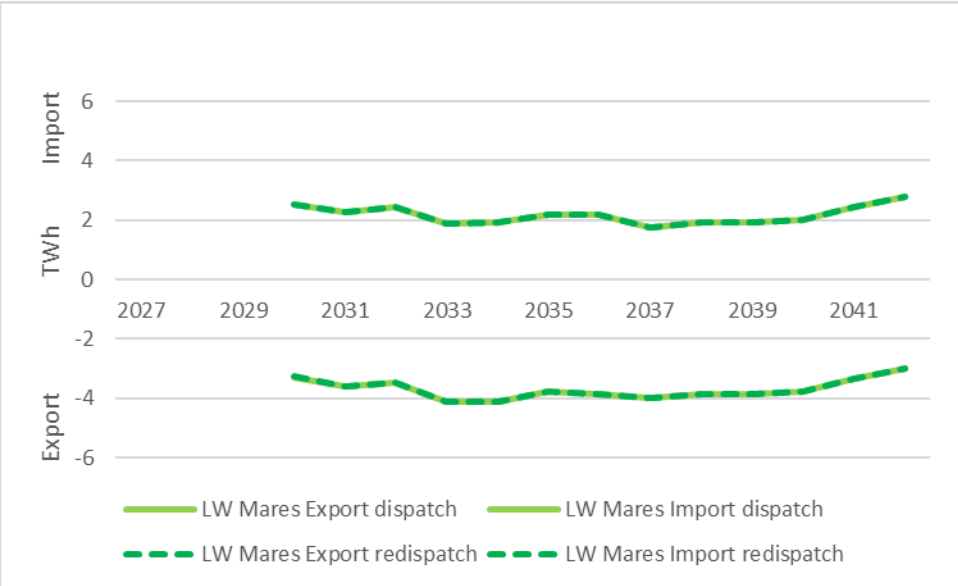


Figure 183: Additional annual constraint costs (discounted) due to MaresConnect for the Marginal Additional case for Falling Short, without and with Constraint Reduction Factor applied.



Annual import and export flows for dispatch and redispatch

Figure 184: Annual import and export flows for MaresConnect in the FA case for Leading the Way.



The above figure shows high exports and low imports in the dispatch. The redispatch shows the same levels of exports and imports as the dispatch. This is because the BID3 model is configured to model as accurately as possible the actual operation of the transmission system. Compared to the original (March 2024) results, imports are significantly higher and exports are significantly lower.

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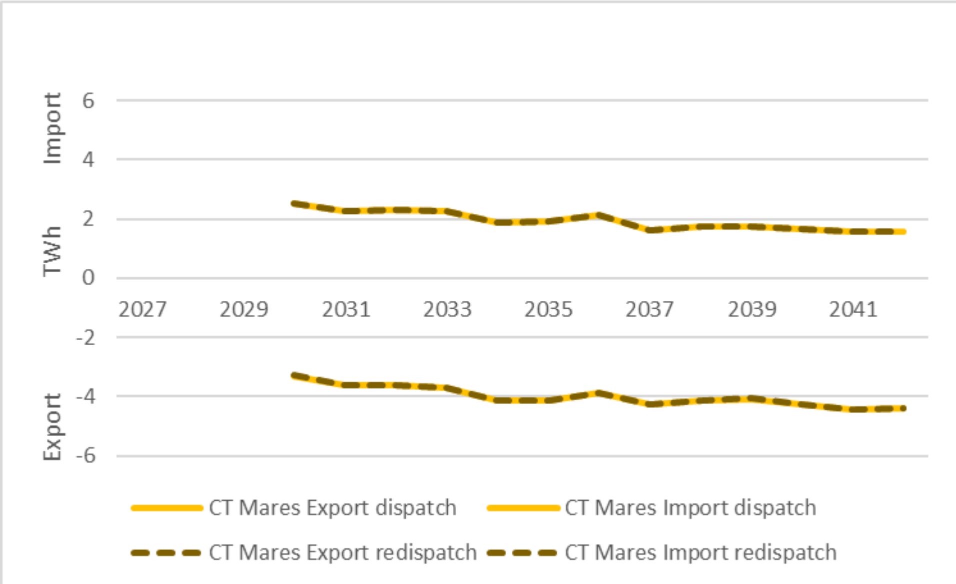
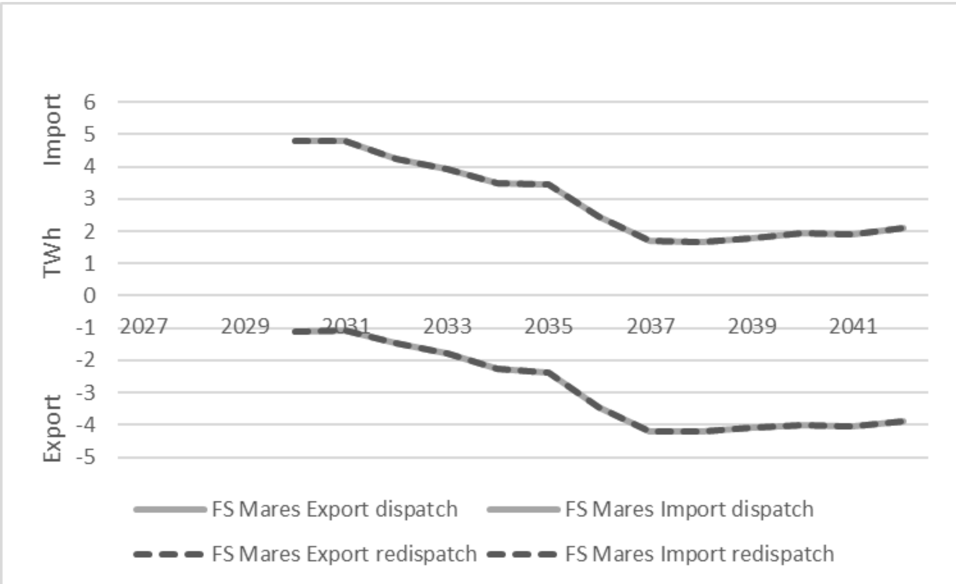
Figure 185: Annual import and export flows for MaresConnect in the FA case for Consumer Transformation.



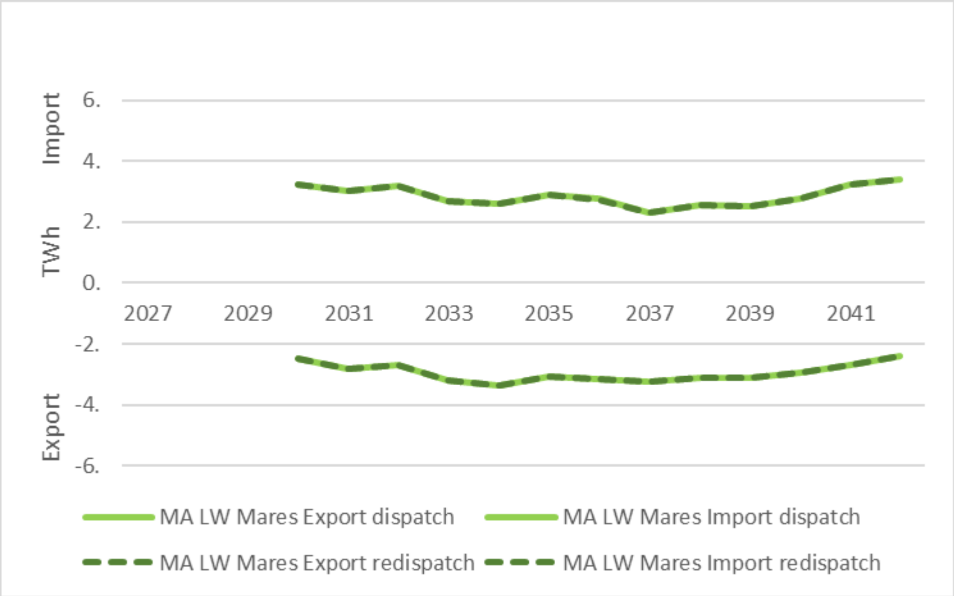
The above figure shows high exports and low imports in the dispatch. The redispatch shows the same levels of exports and imports as the dispatch. This is because the BID3 model is configured to model as accurately as possible the actual operation of the transmission system. Compared to the original (March 2024) results, imports are significantly higher and exports are significantly lower.

Figure 186: Annual import and export flows for MaresConnect in the FA case for Falling Short.



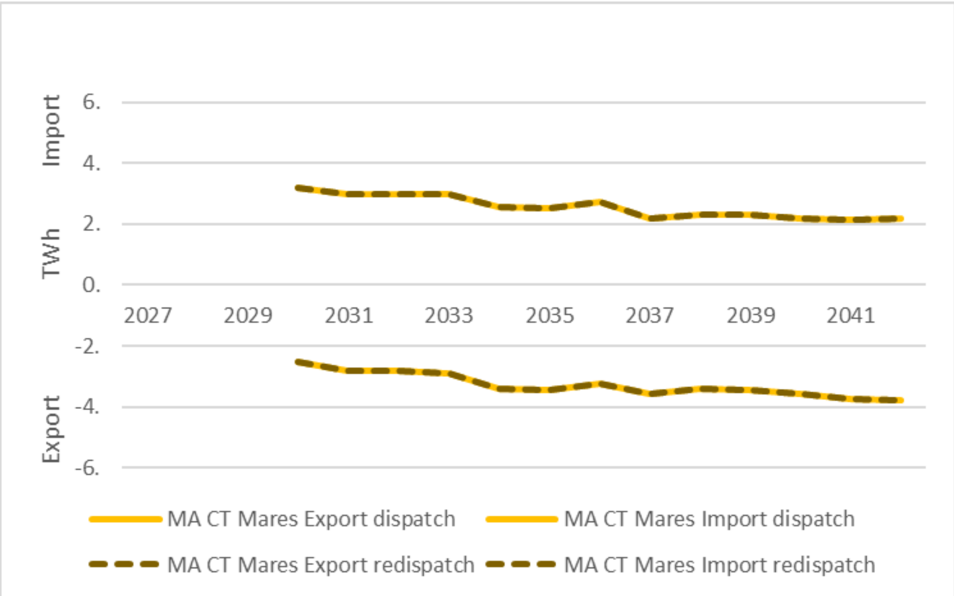
The above figure shows high exports and low imports in the dispatch at the start of the forecast period. Exports increase up to 2037 as imports decline. The redispatch shows the same levels of exports and imports as the dispatch. This is because the BID3 model is configured to model as accurately as possible the actual operation of the transmission system. Compared to the original (March 2024) results, imports are significantly higher and exports are lower.

Figure 187: Annual import and export flows for MaresConnect in the MA case for Leading the Way.



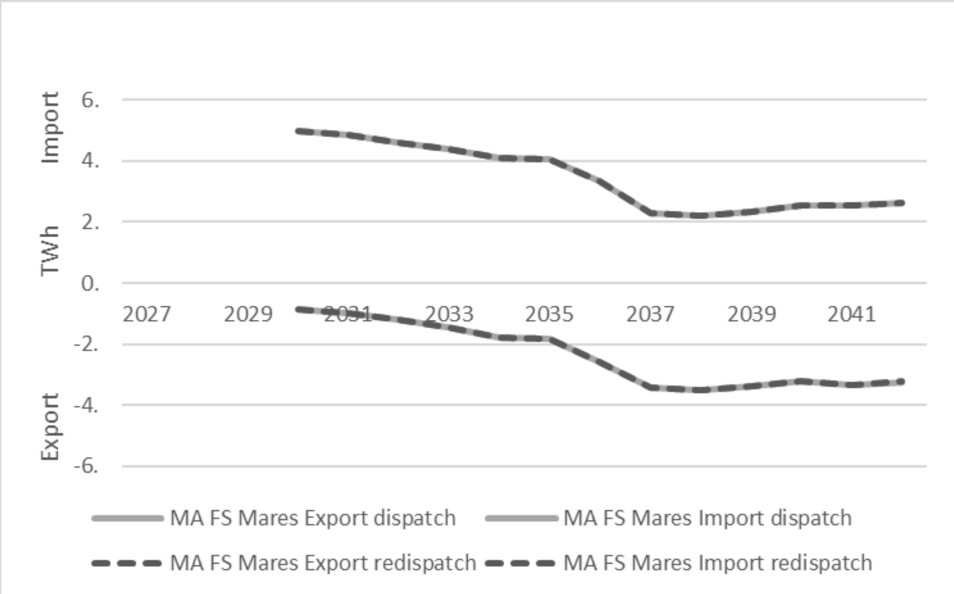
The above figure shows for the dispatch high imports and lower imports. The redispatch shows the same levels of exports and imports as the dispatch. This is because the BID3 model is configured to model as accurately as possible the actual operation of the transmission system. Compared to the original (March 2024) results, imports are significantly higher and exports are significantly lower.

Figure 188: Annual import and export flows for MaresConnect in the MA case for Consumer Transformation.



The above figure shows for the dispatch high imports and lower imports. The redispatch shows the same levels of exports and imports as the dispatch. This is because the BID3 model is configured to model as accurately as possible the actual operation of the transmission system. Compared to the original (March 2024) results, imports are significantly higher and exports are significantly lower.

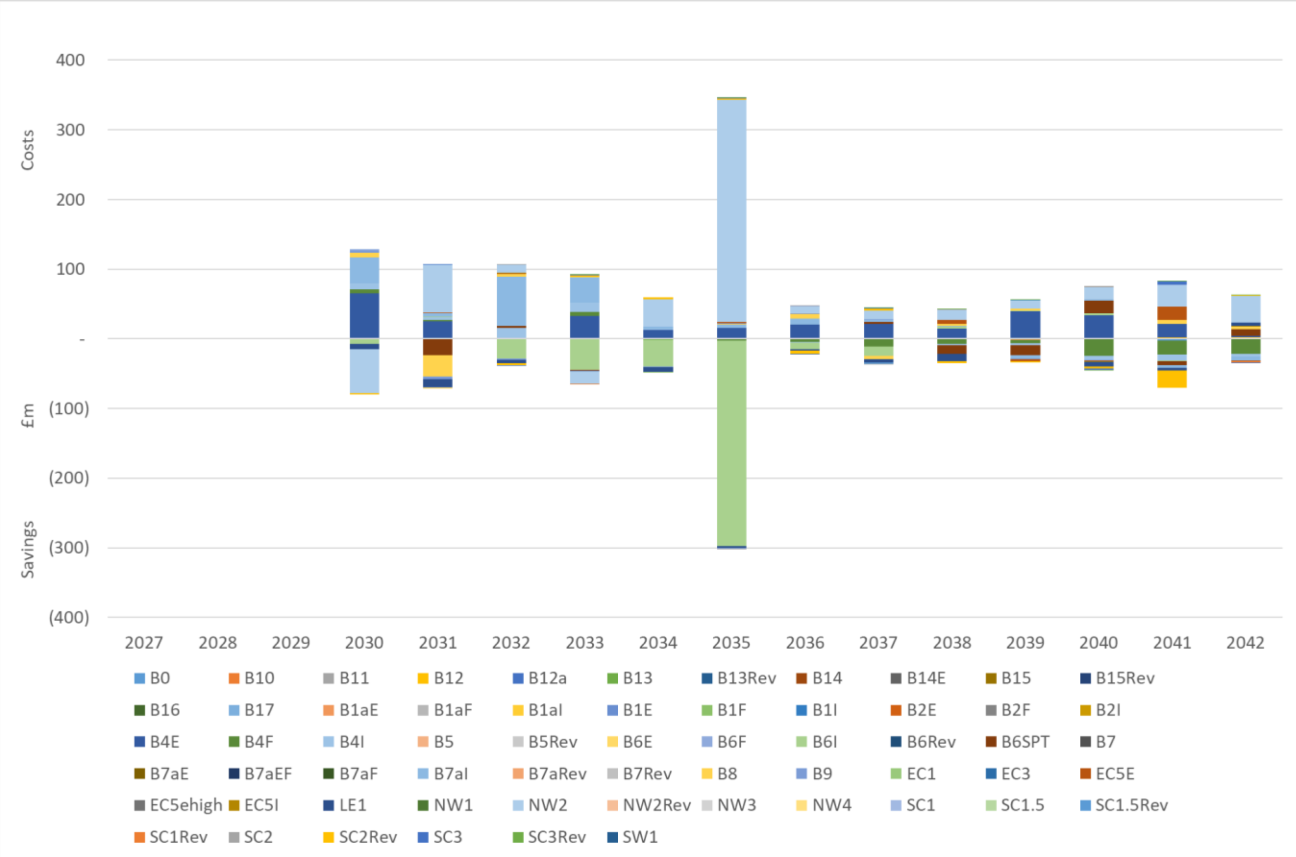
Figure 189: Annual import and export flows for MaresConnect in the MA case for Falling Short.



The above figure shows high exports and low imports in the dispatch at the start of the forecast period. Exports increase up to 2037 as imports decline. The redispatch shows the same levels of exports and imports as the dispatch. This is because the BID3 model is configured to model as accurately as possible the actual operation of the transmission system. Compared to the original (March 2024) results, imports are significantly higher and exports are significantly lower.

Change in constraint costs by boundary

Figure 190: Change in constraint costs by boundary for MaresConnect for the First Additional case for Leading the Way.



The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for MaresConnect for the First Additional case for the Leading the Way scenario. Each different colour represents the change in constraint costs for a particular boundary. It is important to note that the chart shows changes in constraint costs by boundary, i.e. the difference between constraint costs when the project is included and when the project is excluded.

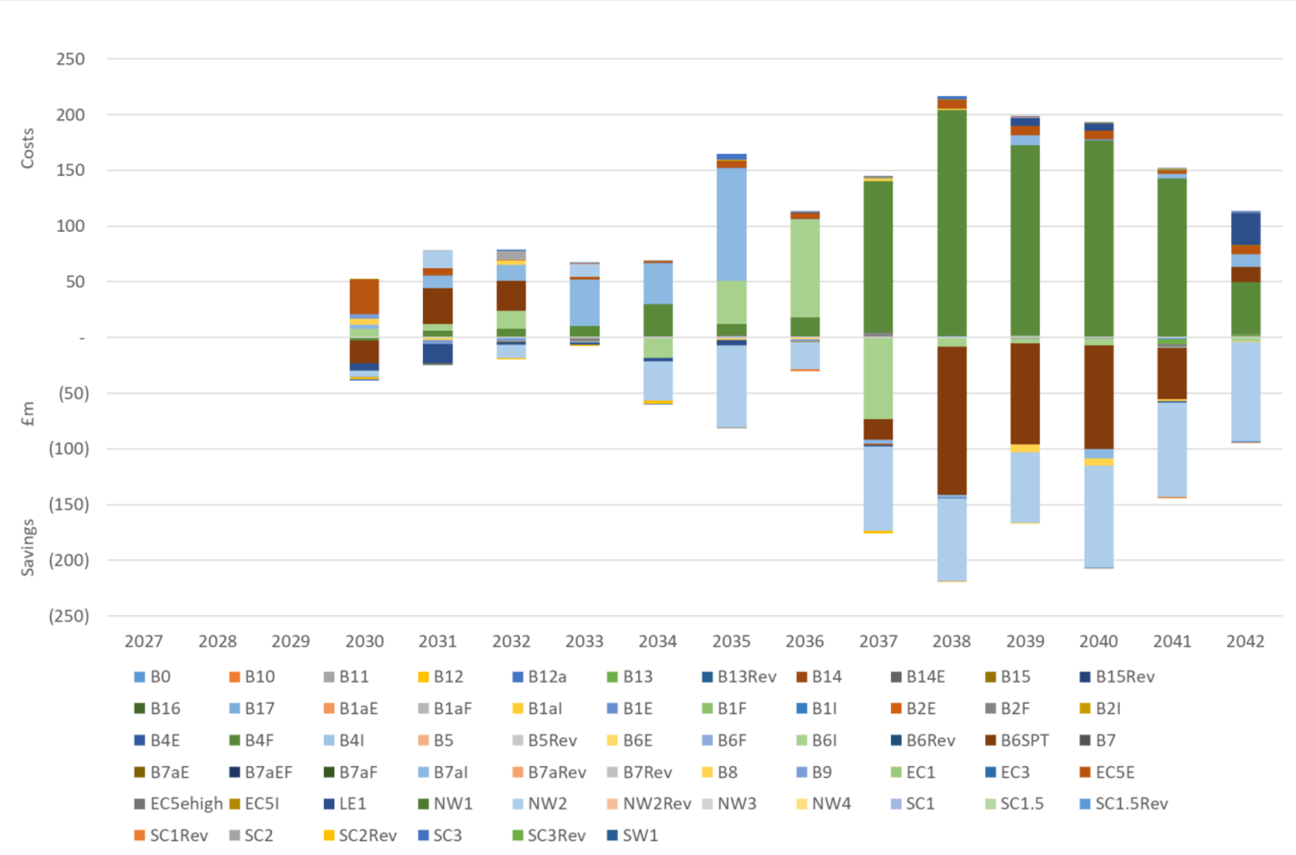
The figure shows that MaresConnect increases constraint costs on certain boundaries but also reduces constraint costs on others. Whether the impact is an increase in constraint costs or a reduction in constraint costs for a particular boundary, changes from year to year. The size of change in constraint costs by boundary can also vary significantly from year to year. This is shown clearly in the years 2034 to 2035. The figure also shows that the specific boundaries that have the greatest impact on the total change in constraint costs can vary from year to year. These factors are a result of the changes in demand, supply and network capability over time.

In general, MaresConnect increases constraint costs on several northern and one Welsh boundary but relieves congestion on various boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

MaresConnect also relieves congestion on one particular northern boundary in 2034. The saving only occurs for a single year suggesting the combination of supply, demand and boundary capabilities that enable such a significant saving across one boundary when MaresConnect is included only exist for that year. That is in later years, supply and demand patterns and boundary capabilities will have evolved such that the model is no longer able to produce the lowest total cost solution by significantly reducing constraint costs across that particular boundary when MaresConnect is included.

Compared to the original (March 2024) analysis, constraint costs are lower on one particular northern boundary.

Figure 191: Change in constraint costs by boundary for MaresConnect for the First Additional case for Consumer Transformation.

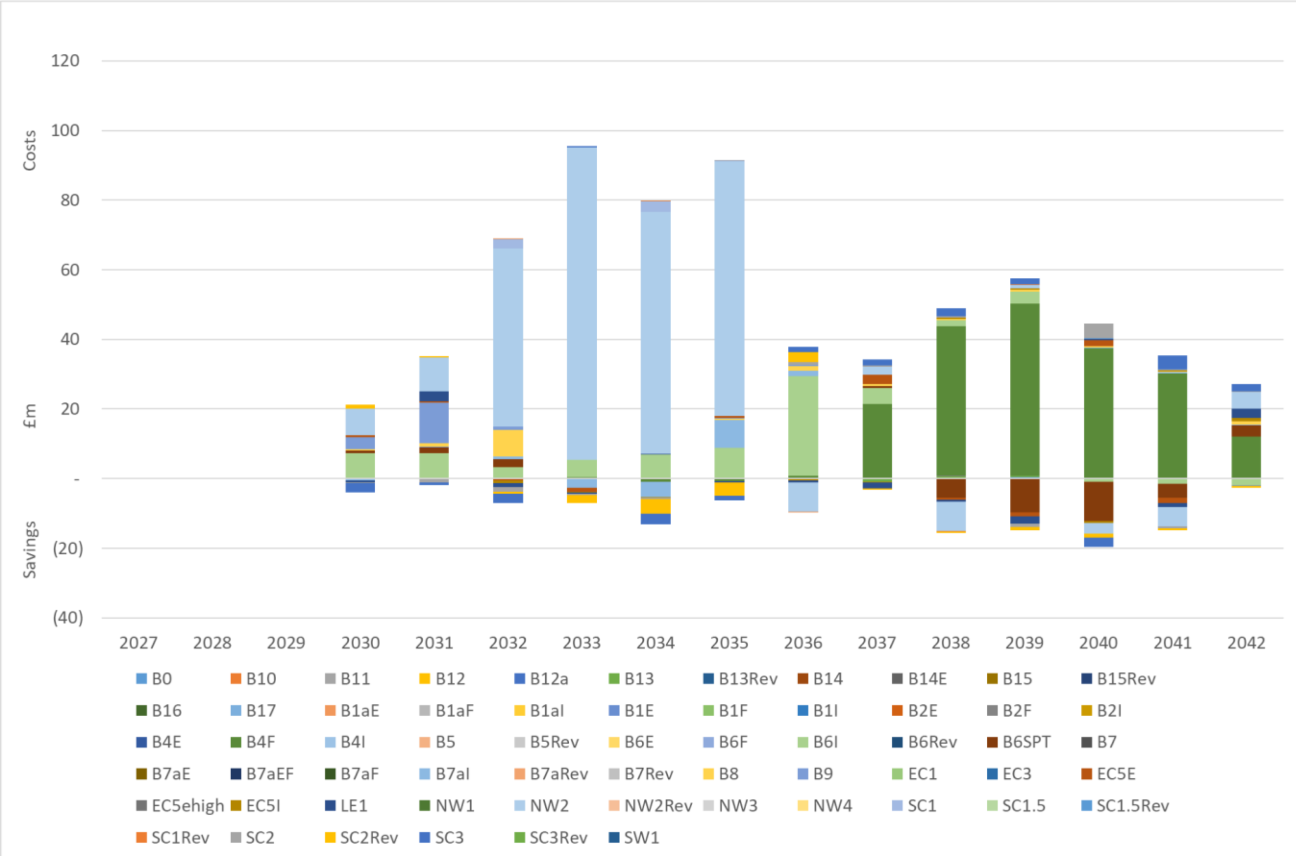


The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for MaresConnect for the First Additional case for the Consumer Transformation scenario.

In general, MaresConnect increases constraint costs on several northern boundaries, but relieves congestion on other northern boundaries and one Welsh boundary. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis, constraint costs are lower on several northern boundaries.

Figure 192: Change in constraint costs by boundary for MaresConnect for the First Additional case for Falling Short.

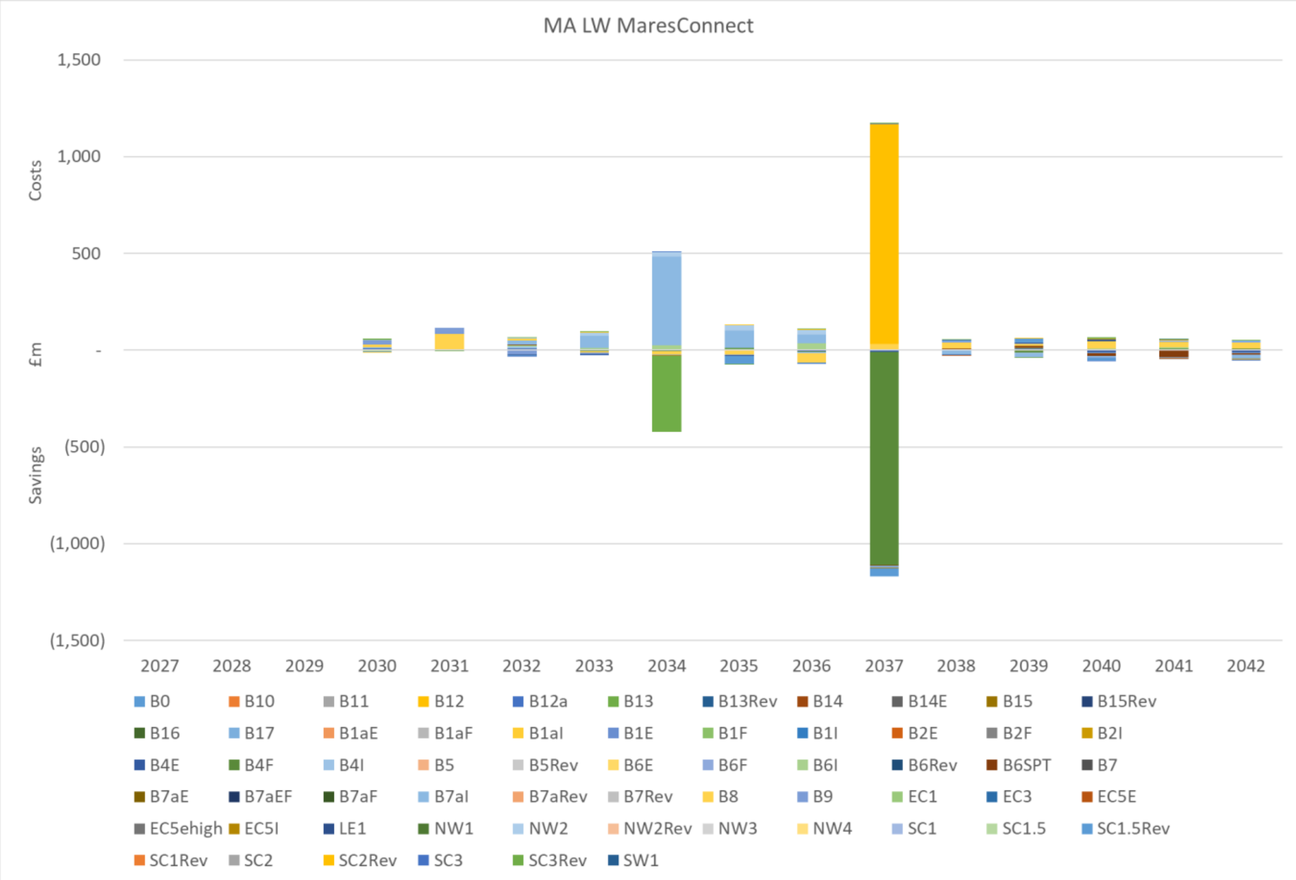


The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for MaresConnect for the First Additional case for the Falling Short scenario.

In general, MaresConnect increases constraint costs on several northern and midland boundaries and one Welsh boundary. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis, constraint costs are higher on one Welsh and various northern boundaries.

Figure 193: Change in constraint costs by boundary for MaresConnect for the Marginal Additional case for Leading the Way.



The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for MaresConnect for the Marginal Additional case for the Leading the Way scenario.

In general, MaresConnect increases constraint costs on several northern boundaries, but relieves congestion on various boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

MaresConnect relieves significant congestion on one southern boundary in 2034 and one northern boundary in 2037. The saving only occurs for a single year suggesting the combination of supply, demand and boundary capabilities that enable such a significant saving across one boundary when MaresConnect is included only exist for that year. That is in later years, supply and demand patterns and boundary capabilities will have evolved such that the model is no longer able to produce the lowest total cost solution by significantly reducing constraint costs across that particular boundary when MaresConnect is included.

Compared to the original (March 2024) analysis constraint costs are higher on various northern boundaries.

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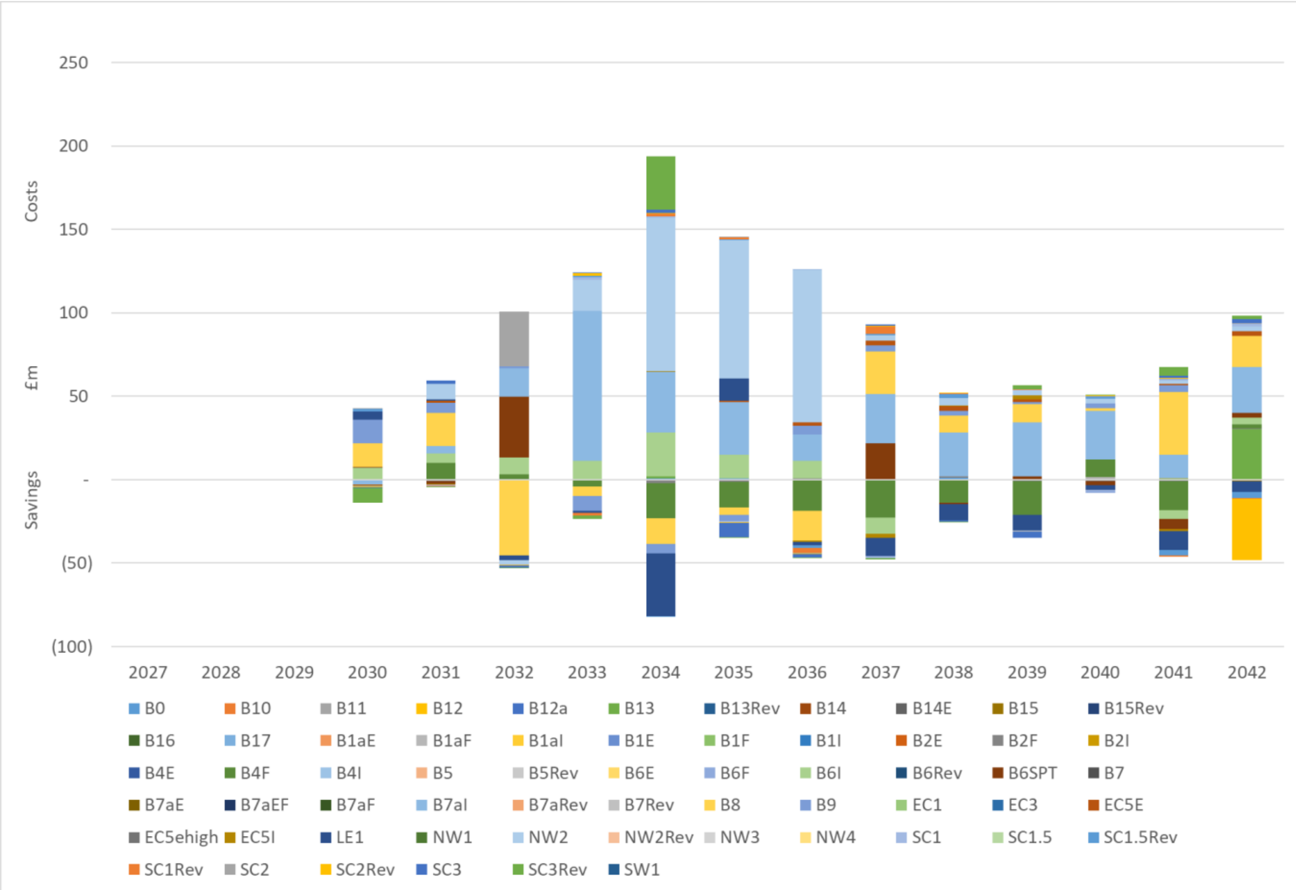
Figure 194: Change in constraint costs by boundary for MaresConnect for the Marginal Additional case for Consumer Transformation.

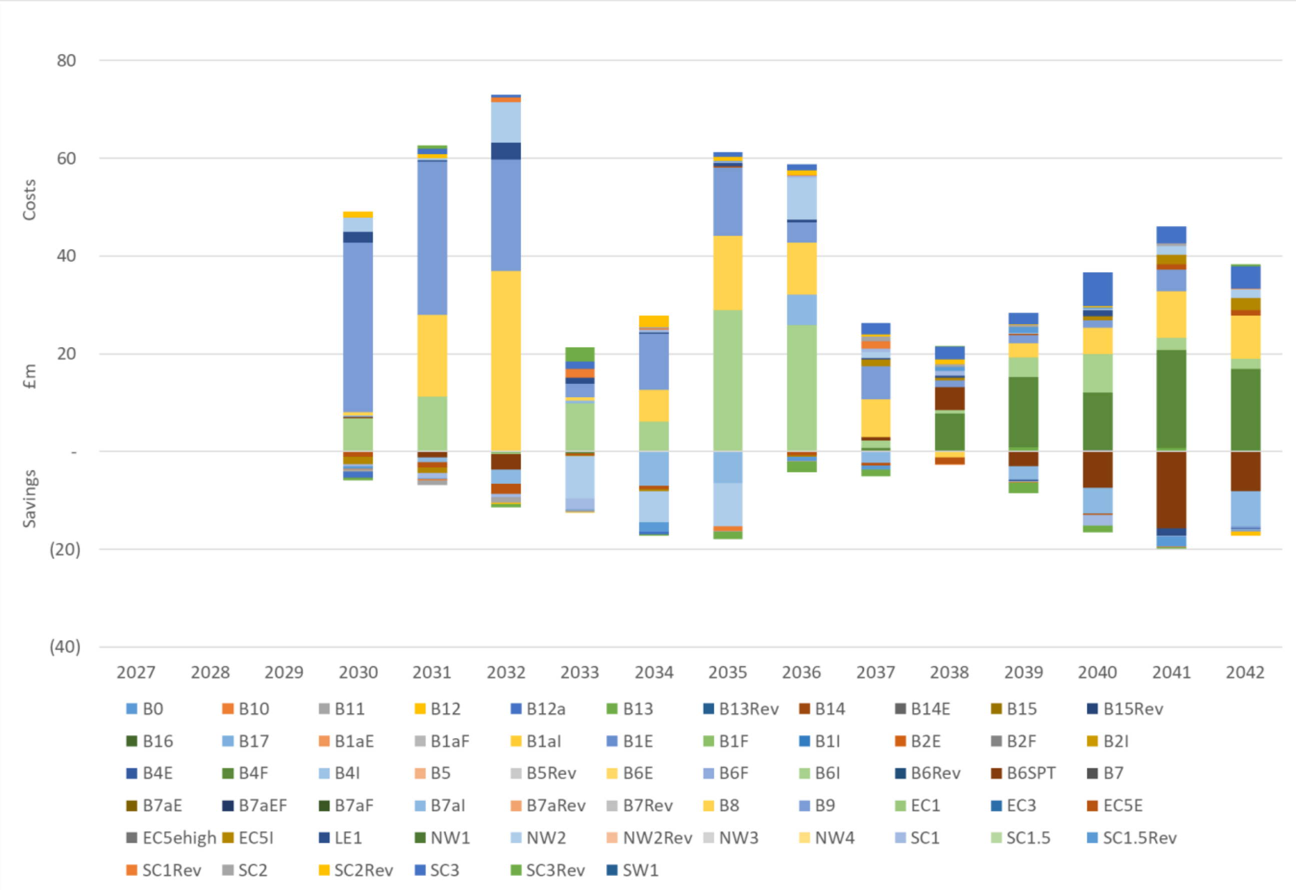


The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for MaresConnect for the Marginal Additional case for the Consumer Transformation scenario.

In general, MaresConnect increases constraint costs on several northern boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis constraint costs are higher on one Welsh and various northern boundaries.

Figure 195: Change in constraint costs by boundary for MaresConnect for the Marginal Additional case for Falling Short.



The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for MaresConnect for the Marginal Additional case for the Falling Short scenario.

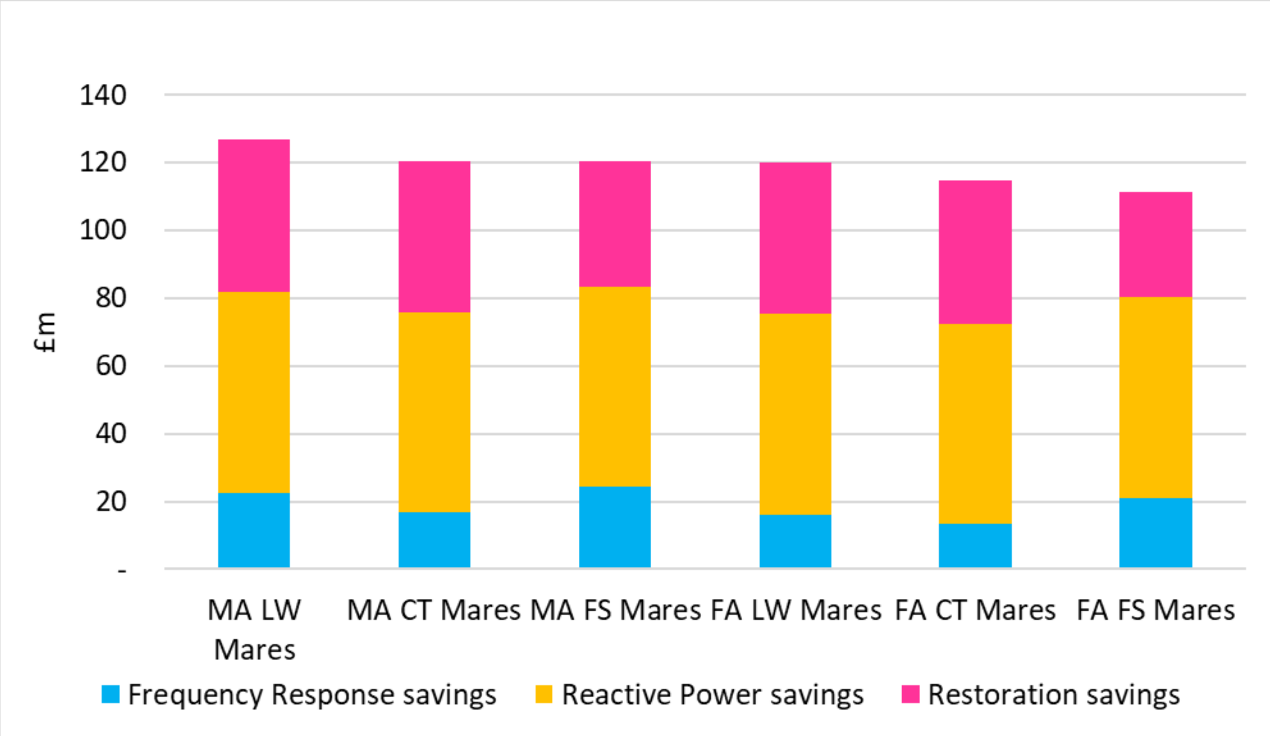
In general, MaresConnect increases constraint costs on several northern boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis constraint costs are higher on various northern boundaries.

PV system operation

Note: The modelling and analysis for system operation is the same as that within the March 2024 report. It was not necessary to repeat the work because the change in modelling assumptions would not produce a material change in the results.

Figure 196: PV potential system operability savings for MaresConnect, Present Value 25-year, real 2022, £m.

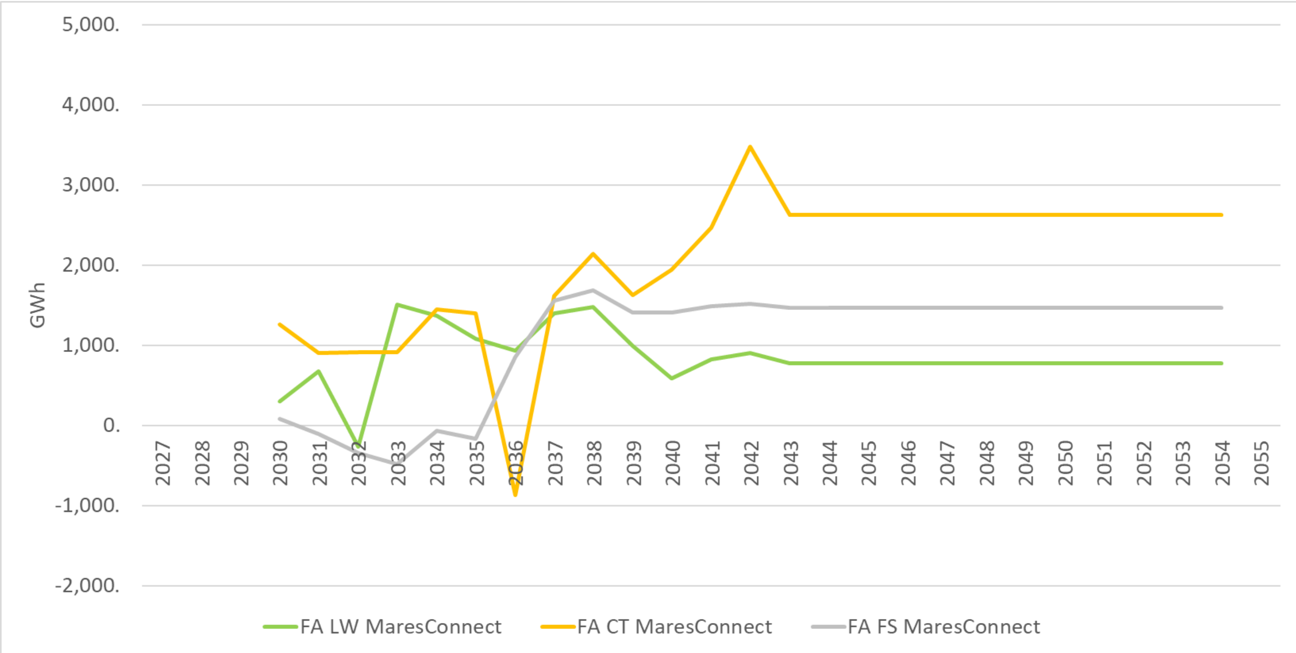


The above figure shows the potential savings for frequency response, reactive power and restoration services in present value (25-year, 2022 £m) for MaresConnect for Leading the Way, Consumer Transformation and Falling Short for both the Marginal Additional and First Additional cases. There is considerable uncertainty around forecasting potential system operability benefits over a 25-year time horizon, but the figure shows that there is potentially significant savings in frequency response, reactive power and restoration services.

There is little variation across the three scenarios and also across the First Additional and Marginal Additional cases. This is because the potential system operability savings from the services provided by MaresConnect are less sensitive to flows across the interconnector, whereas the constraint cost impact is highly dependent on the scale and direction of flows across the project.

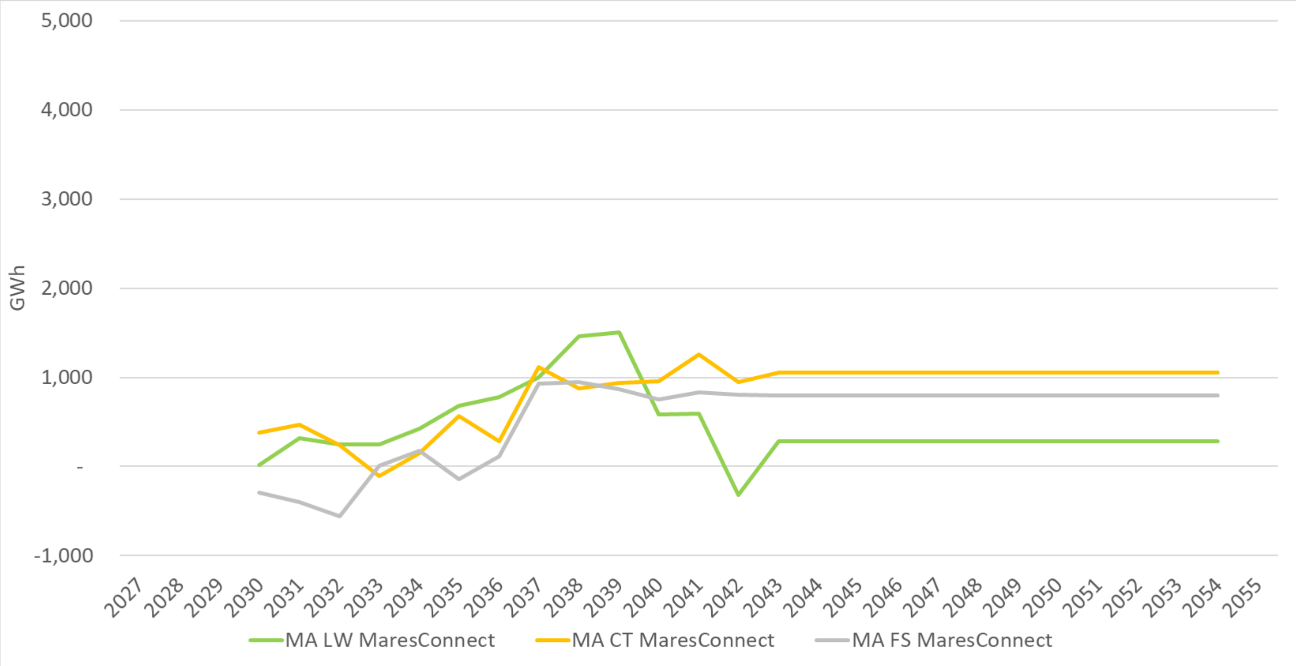
RES curtailment avoided

Figure 197: Annual RES curtailment avoided for MaresConnect for the First Additional case.



The above figure shows the renewable energy supply (RES) curtailment avoided on an annual basis for Leading the Way, Consumer Transformation and Falling Short for the First Additional case. Note that beyond 2042, the results are an average of the years 2040, 2041 and 2042, as our detailed modelling with FES22 only extends out to 2042. The figure shows that the level of annual RES curtailment avoided when MaresConnect is included is approximately between -1TWh and 3TWh, which equates to approximately between a 2.7GWh decrease and a 8.2GWh increase in RES curtailment avoided per day.

Figure 198: Annual RES curtailment avoided for MaresConnect for the Marginal Additional case.



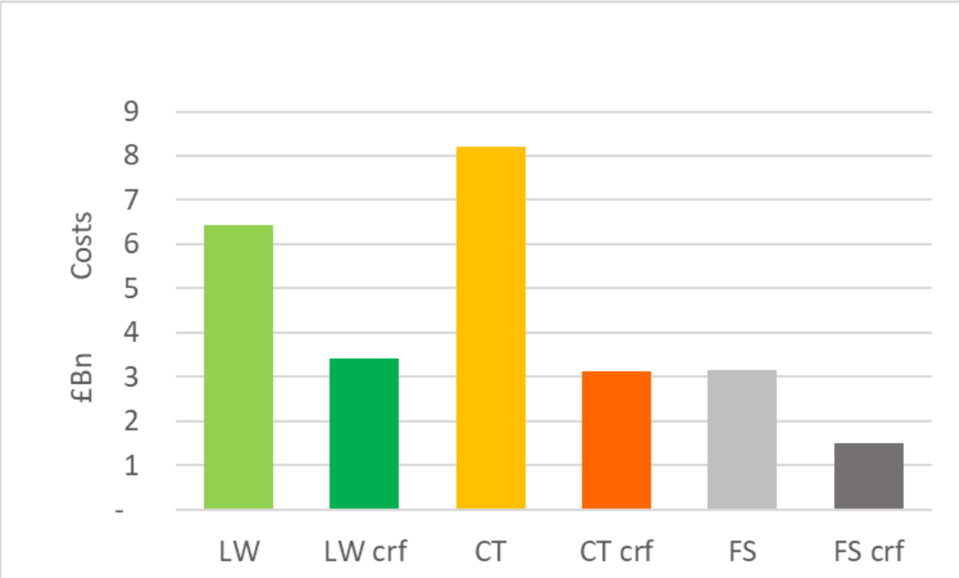
The above figure shows the renewable energy supply (RES) curtailment avoided on an annual basis for Leading the Way, Consumer Transformation and Falling Short for the Marginal Additional case. Note that beyond 2042, the results are an average of the years 2040, 2041 and 2042, as our detailed modelling with FES22 only extends out to 2042. The figure shows that the level of annual RES curtailment avoided when MaresConnect is included rises to approximately between -0.5TWh and 1TWh, which equates to approximately between a 1.4GWh decrease and a 2.7GWh increase in RES curtailment avoided per day.

16. Nautilus

Nautilus is an Offshore Hybrid Asset (OHA) pilot project. It has a capacity of 1.4GW and connects to Belgium. In this latest analysis the capacity of the link between the offshore platform and Belgium has been reduced from 3.5GW to 1.4GW.

PV constraint costs

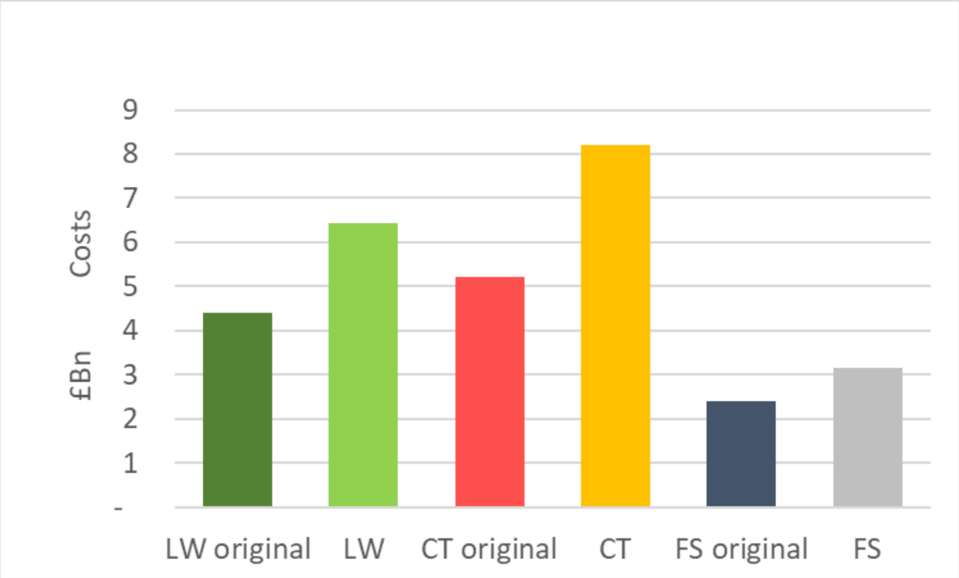
Figure 199: PV additional constraint costs due to Nautilus for the First Additional case, Present Value 25-year, real 2022, £m, without and with Constraint Reduction Factor applied.



The above figure shows the additional constraint costs with the inclusion of Nautilus for the FA case. Without the Constraint Reduction Factor applied, in the Leading the Way scenario (LW) constraint costs are increased by £6.4bn, in Consumer Transformation (CT) by £8.2bn and in the Falling Short (FS) scenario by £3.2bn.

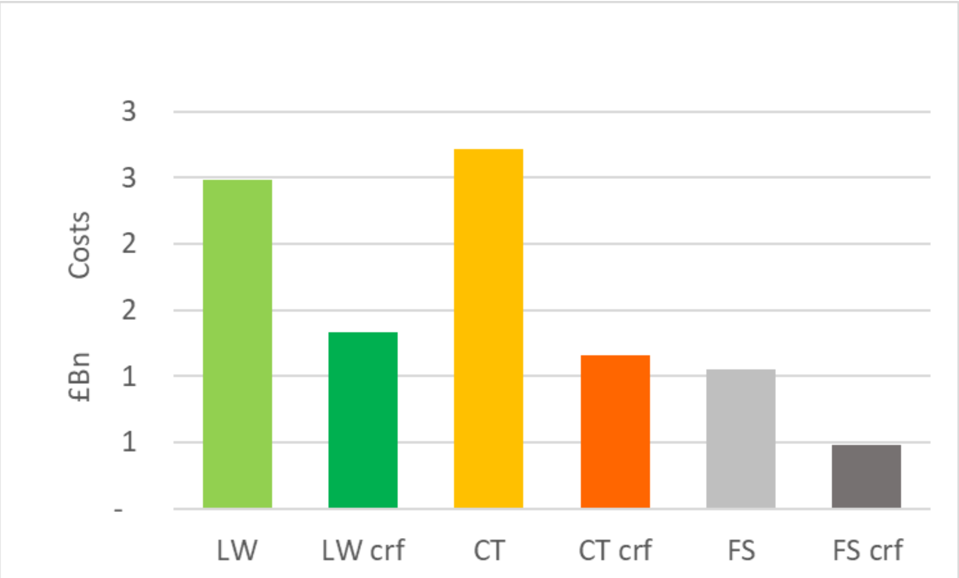
With the Constraint Reduction Factor applied, in the Leading the Way scenario (LW) constraint costs are increased by £3.4bn, in Consumer Transformation (CT) by £3.1bn and in the Falling Short (FS) scenario by £1.5bn.

Figure 200: PV additional constraint costs due to Nautilus for the First Additional case, Present Value 25-year, real 2022, £m, for the original analysis (March 2024) and for Nautilus at Grain with 1.4GW link and Irish demand and generation from TYNDP.



The above figure shows that the changes made to the scenarios, that is the reduction in the capacity of the link connecting the Nautilus offshore platform to Belgium from 3.5GW to 1.4GW and the change in Irish demand and generation to reflect final TYNDP data results in a significant increase in constraint costs in all three scenarios.

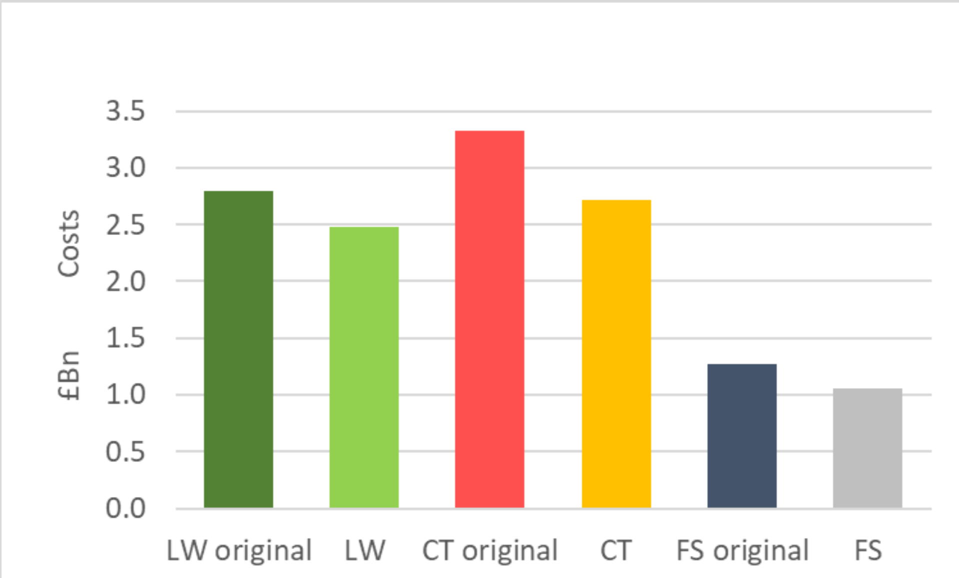
Figure 201: PV additional constraint costs due to Nautilus for the Marginal Additional case, Present Value 25-year, real 2022, £m, without and with Constraint Reduction Factor applied.



The above figure shows the additional constraint costs with the inclusion of Nautilus for the MA case. Without the Constraint Reduction Factor applied, in the Leading the Way scenario (LW) constraint costs are increased by £2.5bn, in Consumer Transformation (CT) by £2.7bn and in the Falling Short (FS) scenario by £1.1bn.

With the Constraint Reduction Factor applied, in the Leading the Way scenario (LW) constraint costs are increased by £1.3bn, in Consumer Transformation (CT) by £1.2bn and in the Falling Short (FS) scenario by £0.48bn.

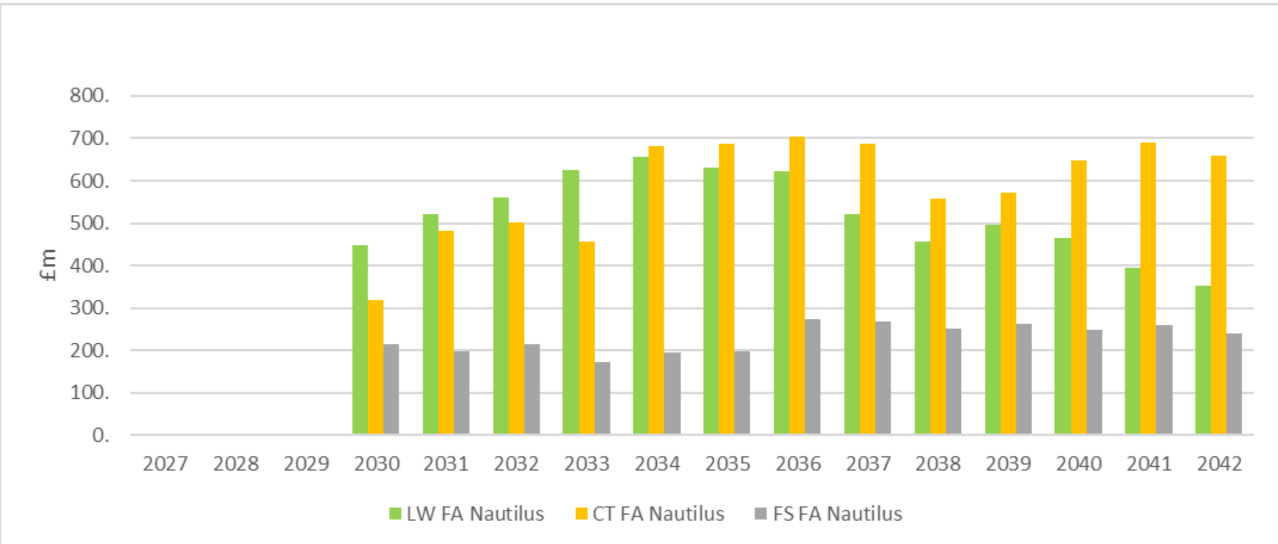
Figure 202: PV additional constraint costs due to Nautilus for the Marginal Additional case, Present Value 25-year, real 2022, £m, for the original analysis (March 2024) and for Nautilus at Grain with 1.4GW link and Irish demand and generation from TYNDP.



The above figure shows that the changes made to the scenarios, that is the reduction in the capacity of the link connecting the Nautilus offshore platform to Belgium from 3.5GW to 1.4GW and the change in Irish demand and generation to reflect final TYNDP data results in a decrease in constraint costs in all three scenarios.

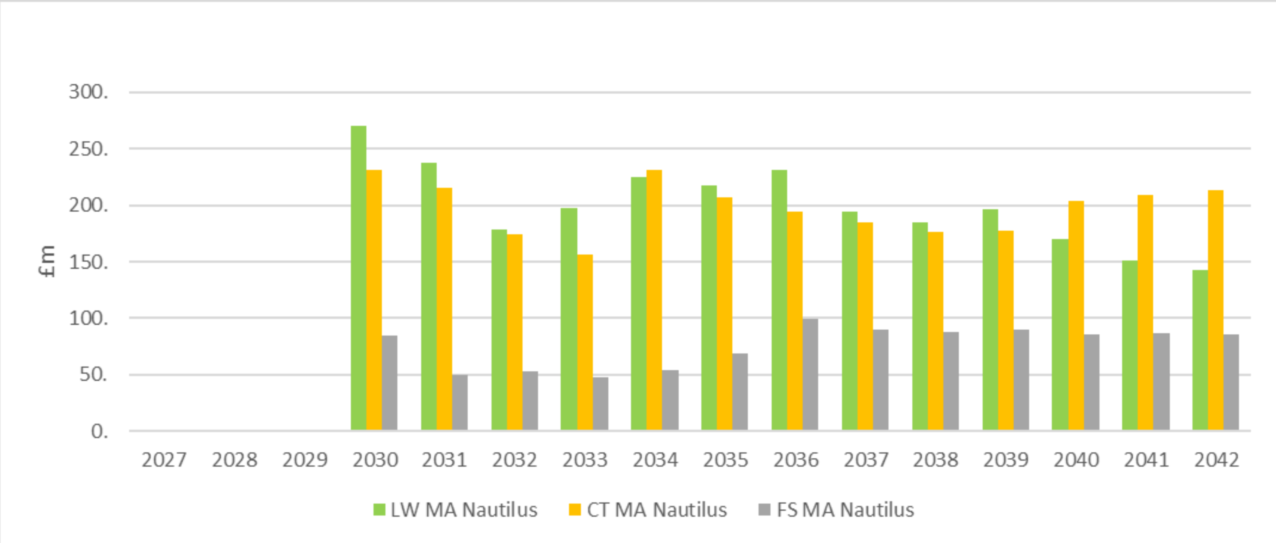
Annual constraint costs (undiscounted)

Figure 203: Additional annual constraint costs (undiscounted) due to Nautilus for the First Additional case.



The above figure shows that Nautilus results in an increase in constraint costs of approximately £400m to £700m (undiscounted) in CT and LW for the years 2031 to 2041. In FS constraint cost increases are much lower, of approximately £200m to £300m. The results are significantly higher than the original (March 2024) results.

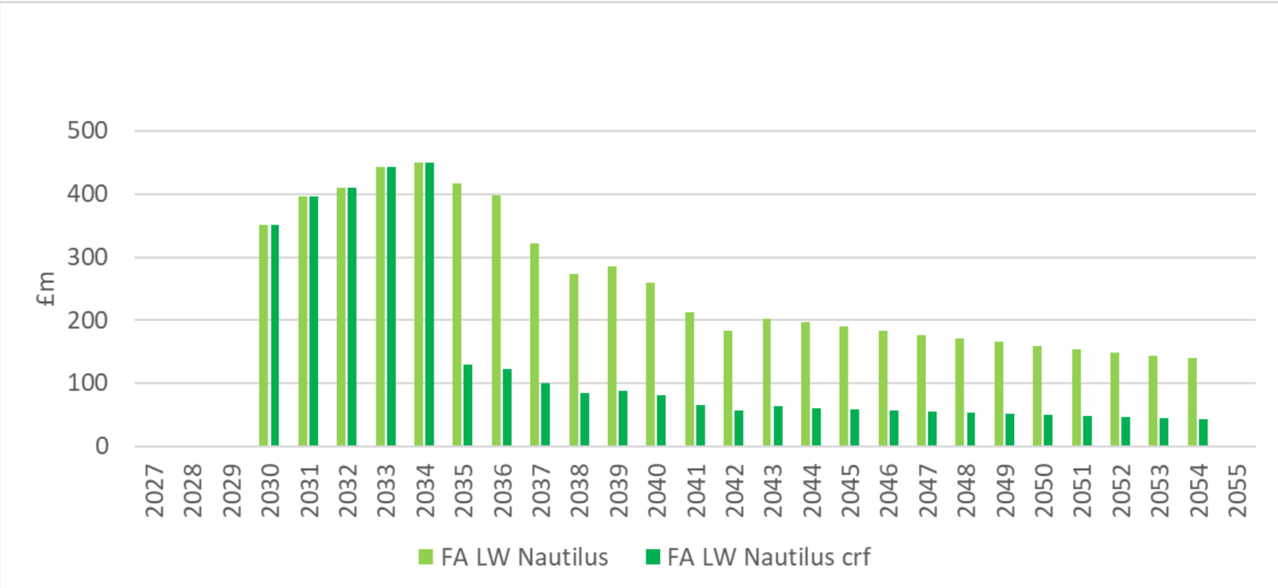
Figure 204: Additional annual constraint costs (undiscounted) due to Nautilus for the Marginal Additional case.



In the Marginal Additional case, Nautilus results in an increase in constraint costs of approximately £150m to £200m (undiscounted) in CT and LW for the years 2032 to 2035. FS shows lower levels of additional constraint costs compared to LW and CT of approximately £50m to £100m. The results for all three scenarios are lower than the original (March 2024) results.

Annual constraint costs (discounted), without and with Constraint Reduction Factor

Figure 205: Additional annual constraint costs (discounted) due to Nautilus for the First Additional case for Leading the Way, without and with Constraint Reduction Factor applied.



The above chart shows the additional constraint costs without and with the Constraint Reduction Factor (CRF) applied for the Leading the Way scenario for the First Additional case. The chart shows the impact of the CRF being applied from 2035 onwards.

Figure 206: Additional annual constraint costs (discounted) due to Nautilus for the First Additional case for Consumer Transformation, without and with Constraint Reduction Factor applied.

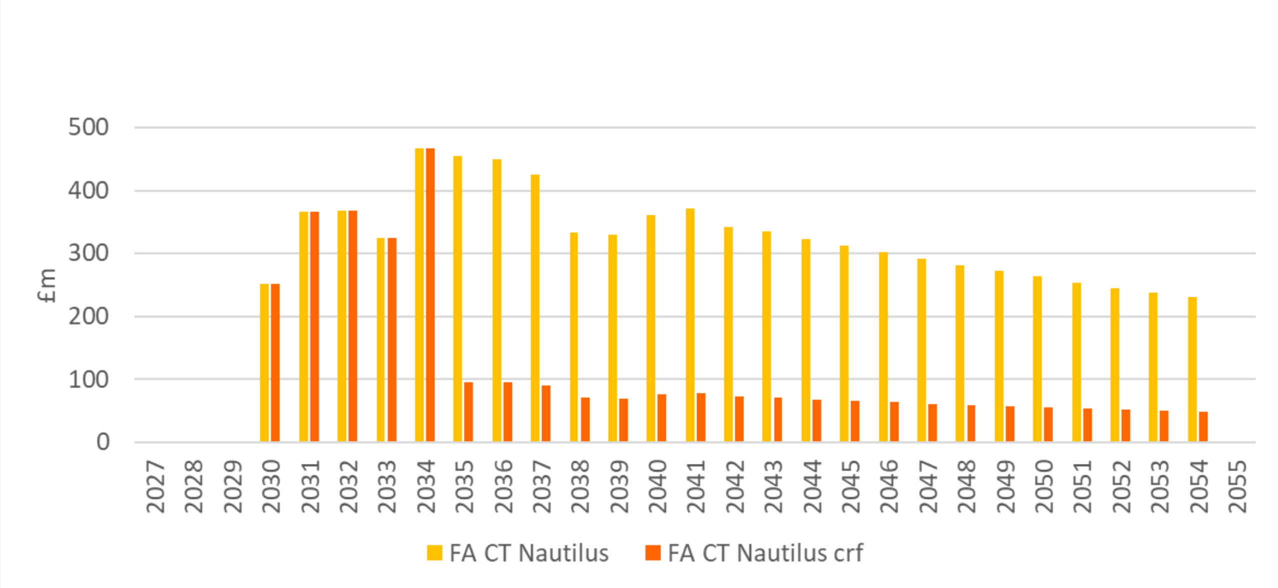


Figure 207: Additional annual constraint costs (discounted) due to Nautilus for the First Additional case for Falling Short, without and with Constraint Reduction Factor applied.

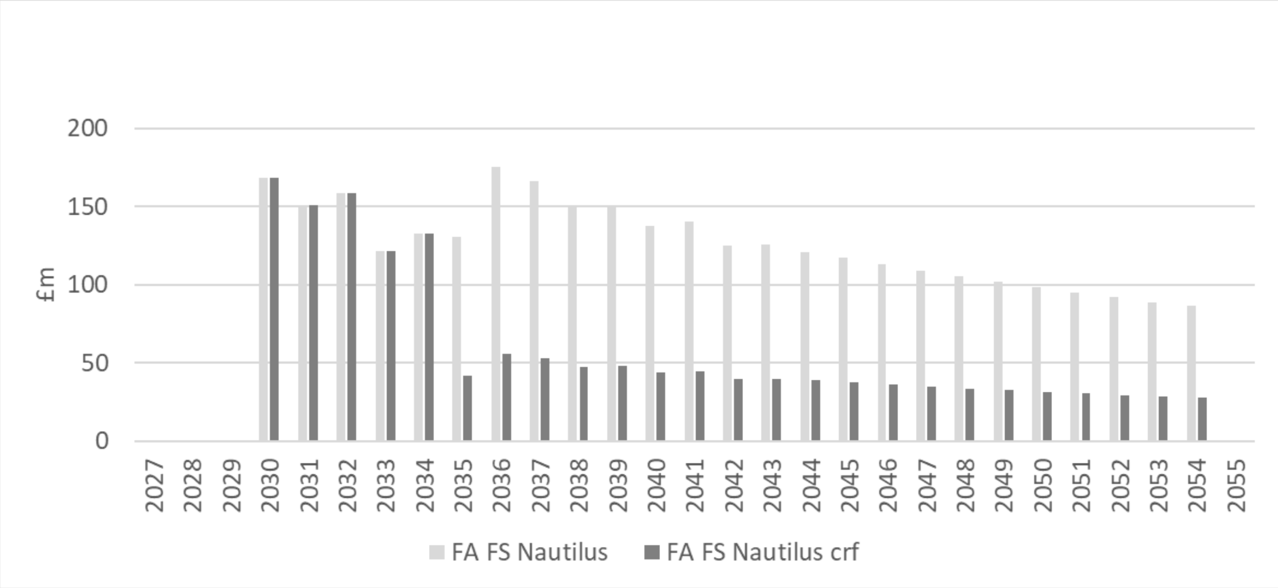
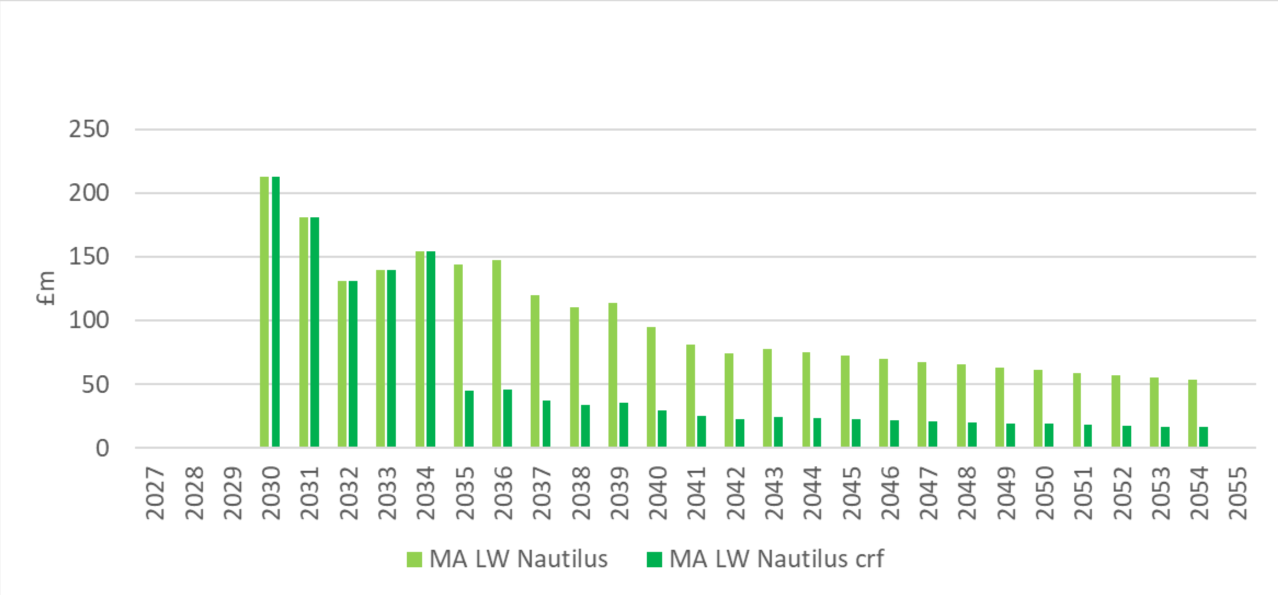


Figure 208: Additional annual constraint costs (discounted) due to Nautilus for the Marginal Additional case for Leading the Way, without and with Constraint Reduction Factor applied.



The above chart shows the additional constraint costs without and with the Constraint Reduction Factor (CRF) applied for the Leading the Way scenario for the Marginal Additional case. The chart shows the impact of the CRF being applied from 2035 onwards.

Figure 209: Additional annual constraint costs (discounted) due to Nautilus for the Marginal Additional case for Consumer Transformation, without and with Constraint Reduction Factor applied.

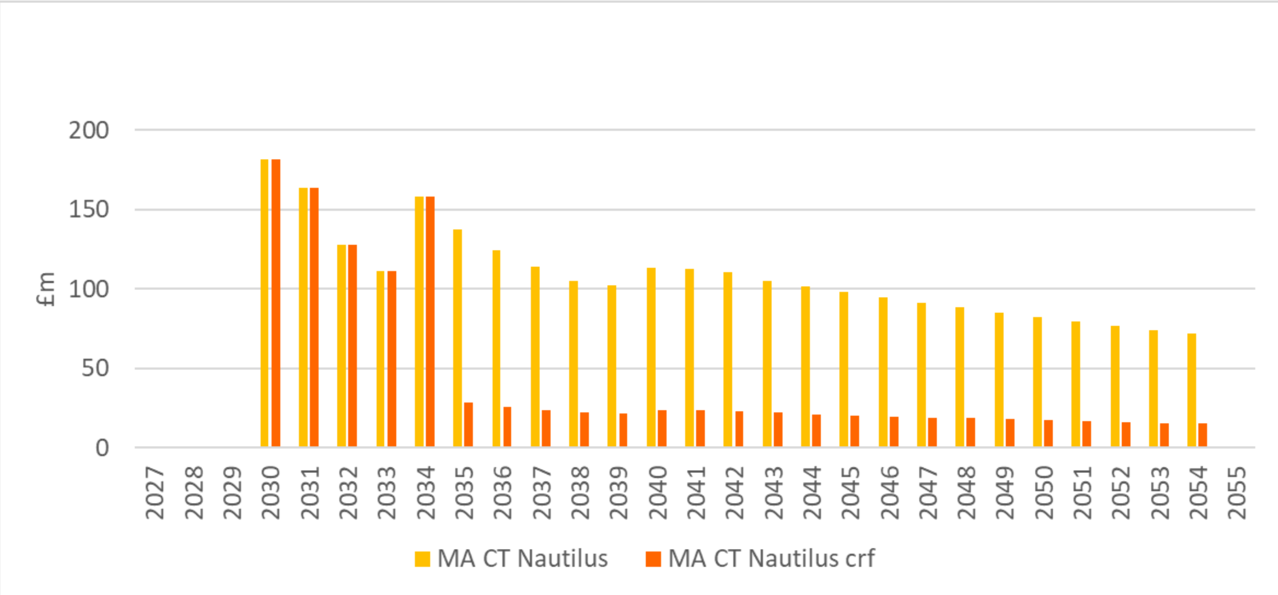
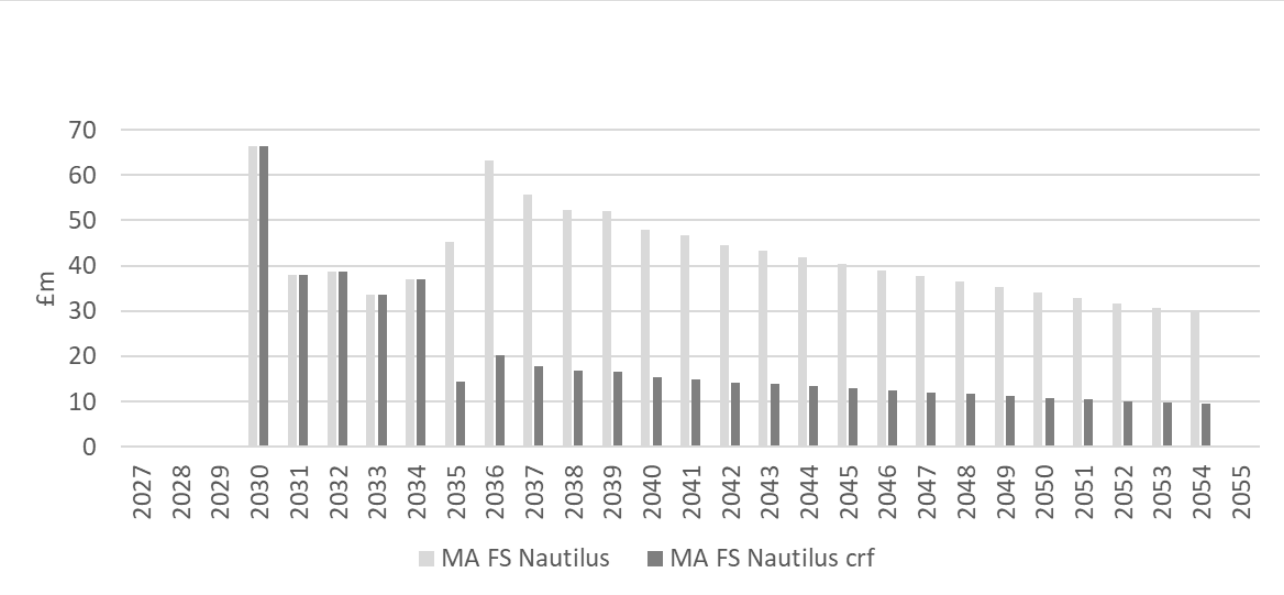
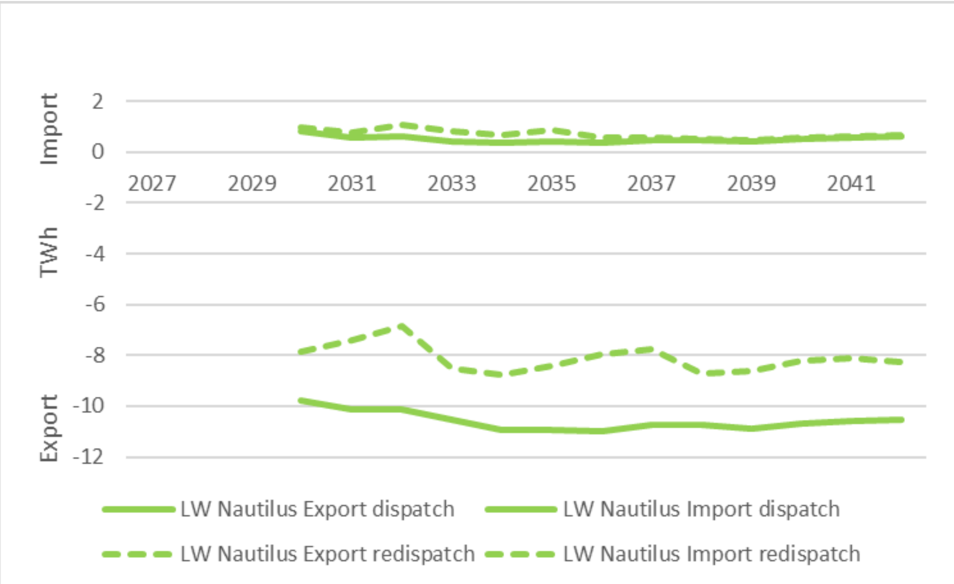


Figure 210: Additional annual constraint costs (discounted) due to Nautilus for the Marginal Additional case for Falling Short, without and with Constraint Reduction Factor applied.



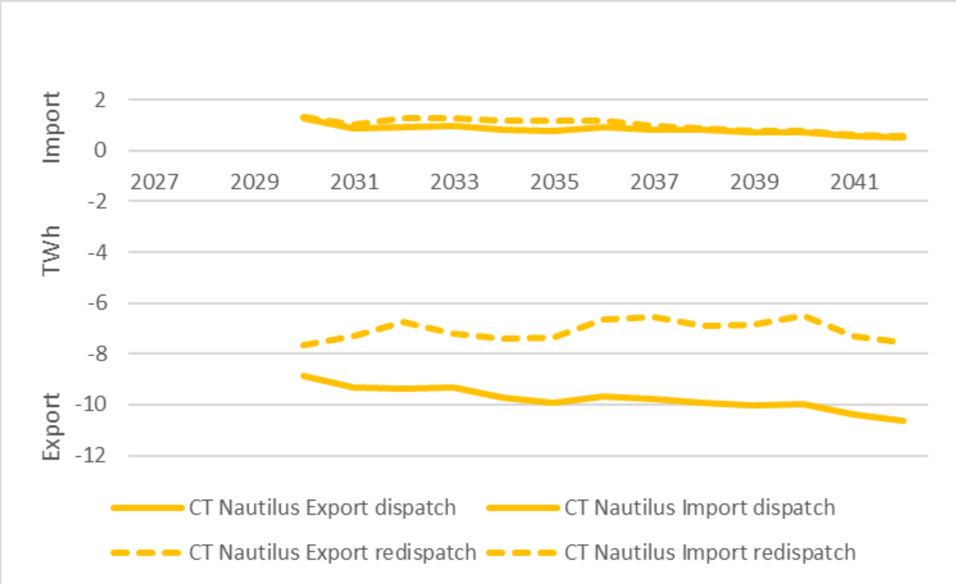
Annual import and export flows for dispatch and redispatch

Figure 211: Annual import and export flows for Nautilus in the FA case for Leading the Way.



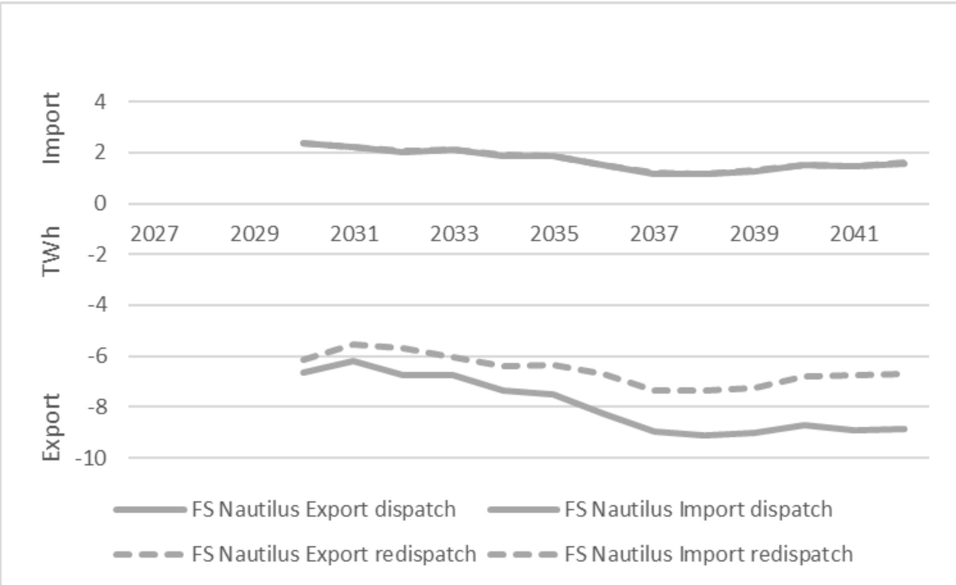
The above figure shows very high exports and very low imports in the dispatch. The redispatch shows a large reduction in exports and a very slight increase in imports. Compared to the original (March 2024) results, exports are significantly higher and imports are slightly lower.

Figure 212: Annual import and export flows for Nautilus in the FA case for Consumer Transformation.



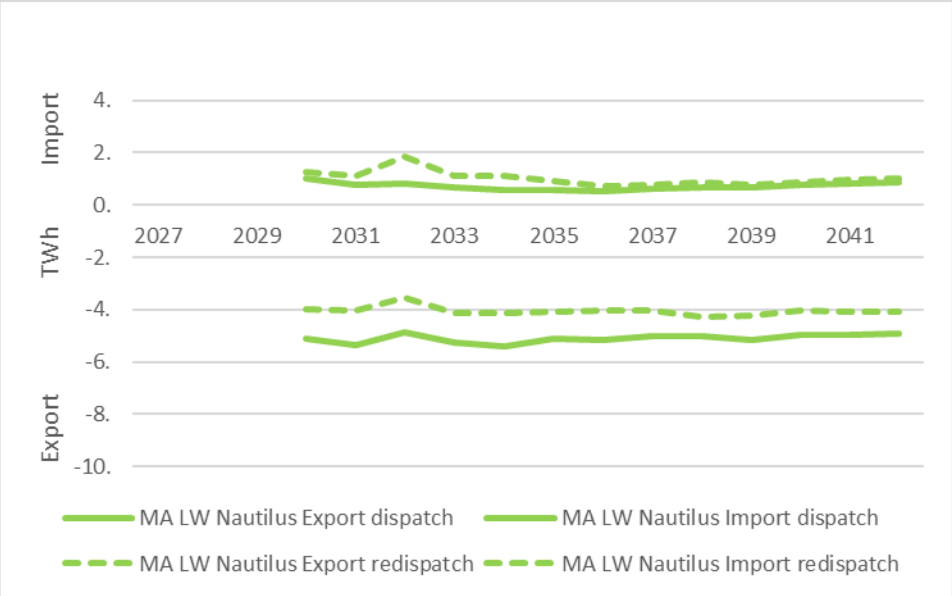
The above figure shows very high exports and low imports in the dispatch. The redispatch shows a large reduction in exports and a very slight increase in imports. Compared to the original (March 2024) results, exports are higher and imports are slightly lower.

Figure 213: Annual import and export flows for Nautilus in the FA case for Falling Short.



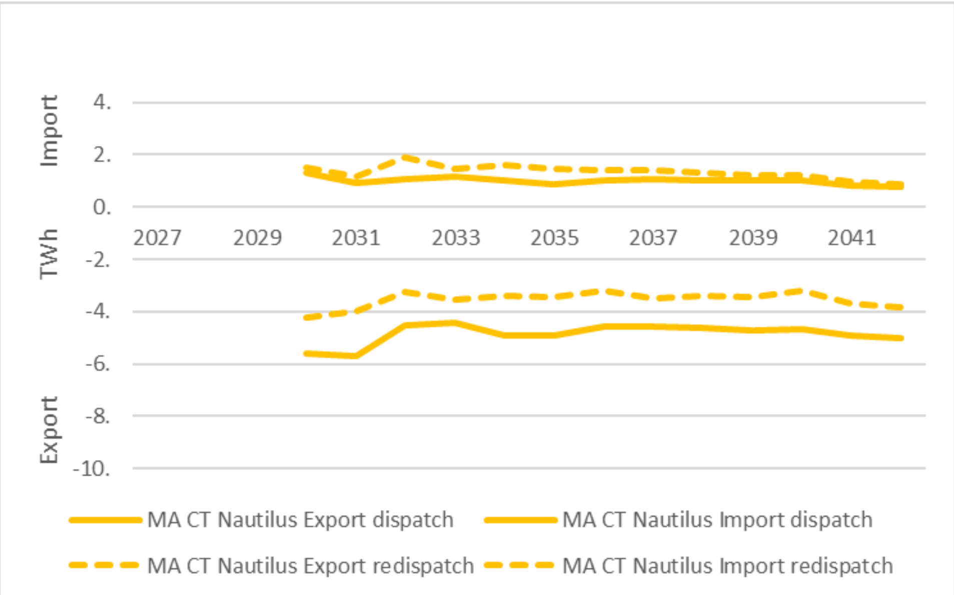
The above figure shows that for the First Additional case Nautilus has increasing levels of exports over the forecast period up to 2038 for Falling Short. The redispatch shows an increasing reduction in exports but little change in imports. Compared to the original (March 2024) results, exports are higher and imports are lower.

Figure 214: Annual import and export flows for Nautilus in the MA case for Leading the Way.



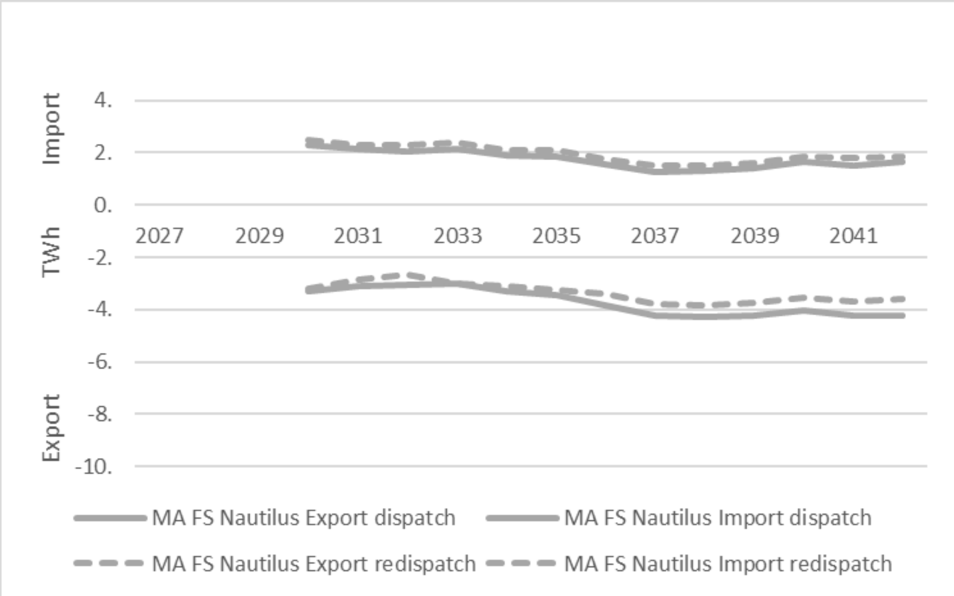
The above figure shows for the dispatch high exports, and low imports. The redispatch shows a significant reduction in exports and a slight increase in imports. Compared to the original (March 2024) results, both exports and imports are lower.

Figure 215: Annual import and export flows for Nautilus in the MA case for Consumer Transformation.



The above figure shows high exports and low imports in the dispatch. The redispatch shows exports reduced significantly and a slight increase in imports. Compared to the original (March 2024) results, both exports and imports are slightly lower.

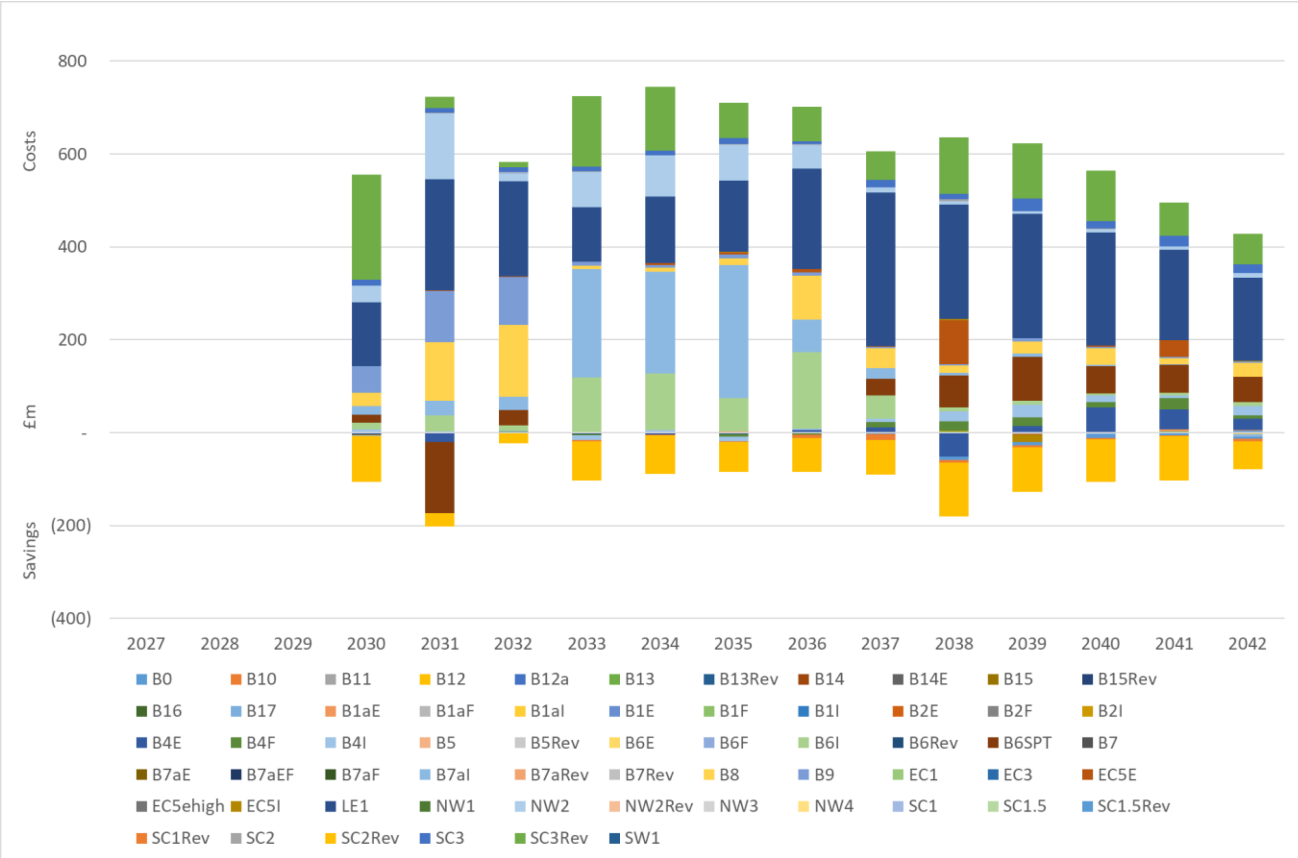
Figure 216: Annual import and export flows for Nautilus in the MA case for Falling Short.



The above figure shows that for the Marginal Additional case, Nautilus has exports increasing slightly over time, and imports decreasing slightly in the dispatch. The redispatch shows some slight reduction in exports and a very small increase in imports. Compared to the original (March 2024) results, exports and imports are lower.

Change in constraint costs by boundary

Figure 217: Change in constraint costs by boundary for Nautilus for the First Additional case for Leading the Way.



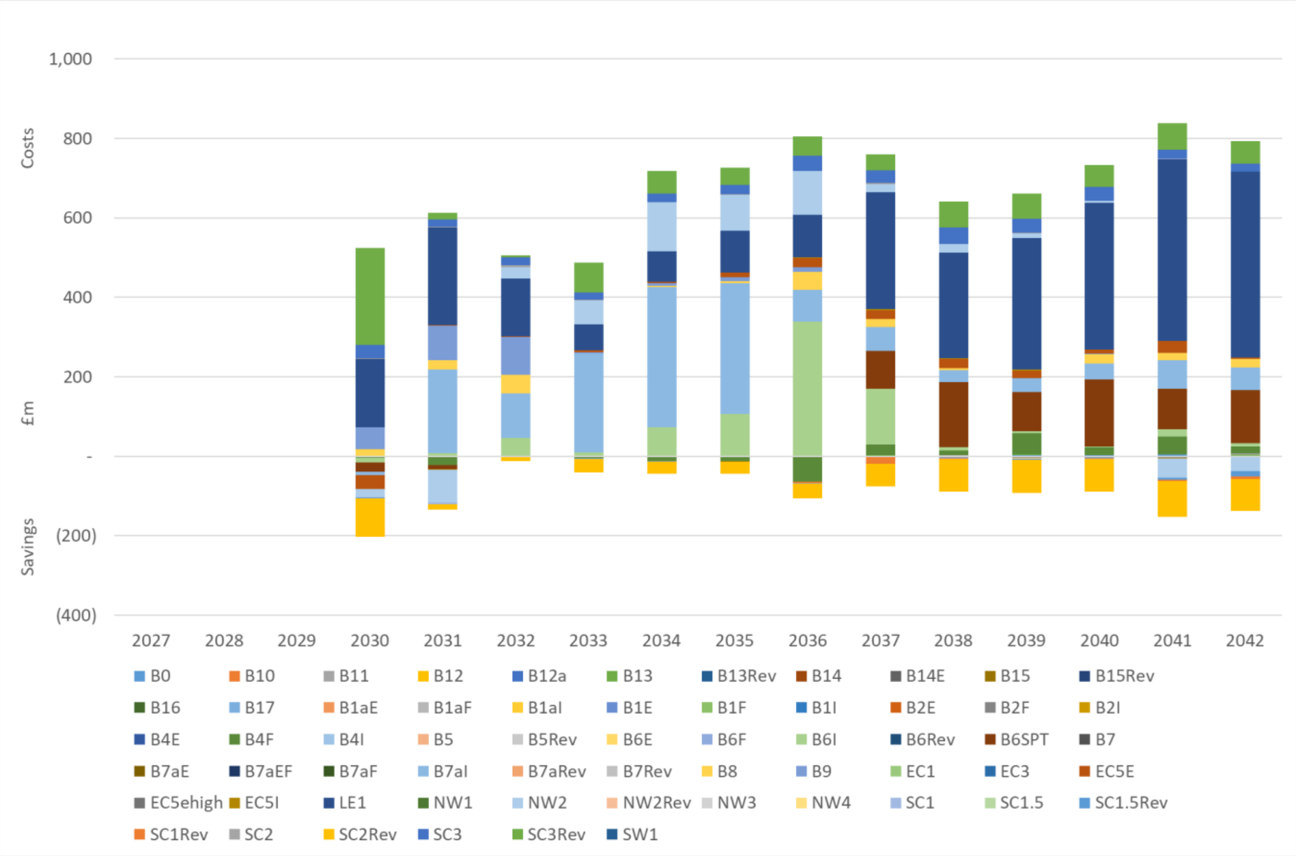
The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for Nautilus for the First Additional case for the Leading the Way scenario. Each different colour represents the change in constraint costs for a particular boundary. It is important to note that the chart shows changes in constraint costs by boundary, i.e. the difference between constraint costs when the project is included and when the project is excluded.

The figure shows that Nautilus increases constraint costs on certain boundaries but also reduces constraint costs on others. Whether the impact is an increase in constraint costs or a reduction in constraint costs for a particular boundary, changes from year to year. The size of change in constraint costs by boundary can also vary significantly from year to year. This is shown clearly in the years 2035 to 2036. The figure also shows that the specific boundaries that have the greatest impact on the total change in constraint costs can vary from year to year. These factors are a result of the changes in demand, supply and network capability over time.

In general, Nautilus increases constraint costs on several northern and southern boundaries but relieves congestion on several boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis constraint costs are higher on various northern and southern boundaries.

Figure 218: Change in constraint costs by boundary for Nautilus for the First Additional case for Consumer Transformation.

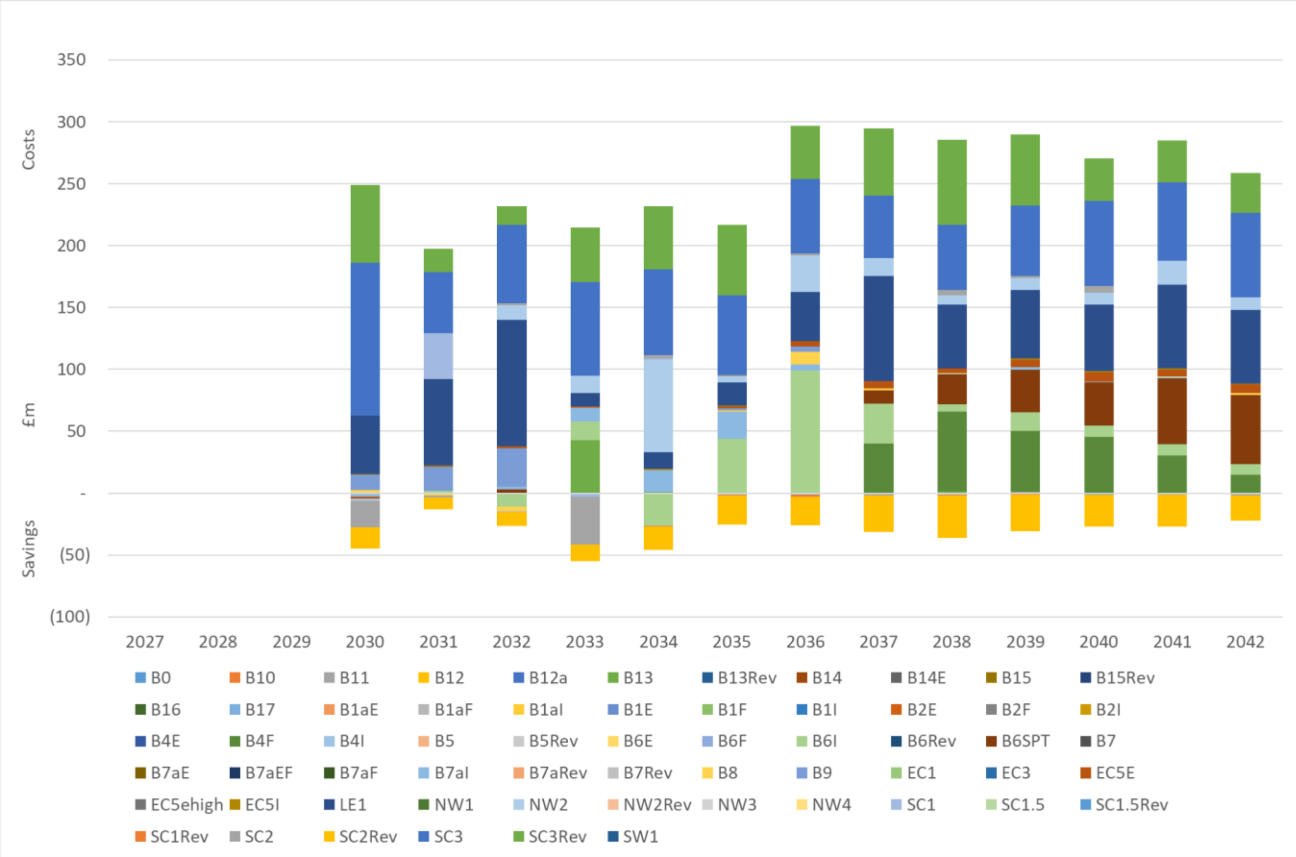


The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for Nautilus for the First Additional case for the Consumer Transformation scenario.

In general, Nautilus increases constraint costs on several northern and southern boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis constraint costs are higher on various northern and southern boundaries.

Figure 219: Change in constraint costs by boundary for Nautilus for the First Additional case for Falling Short.

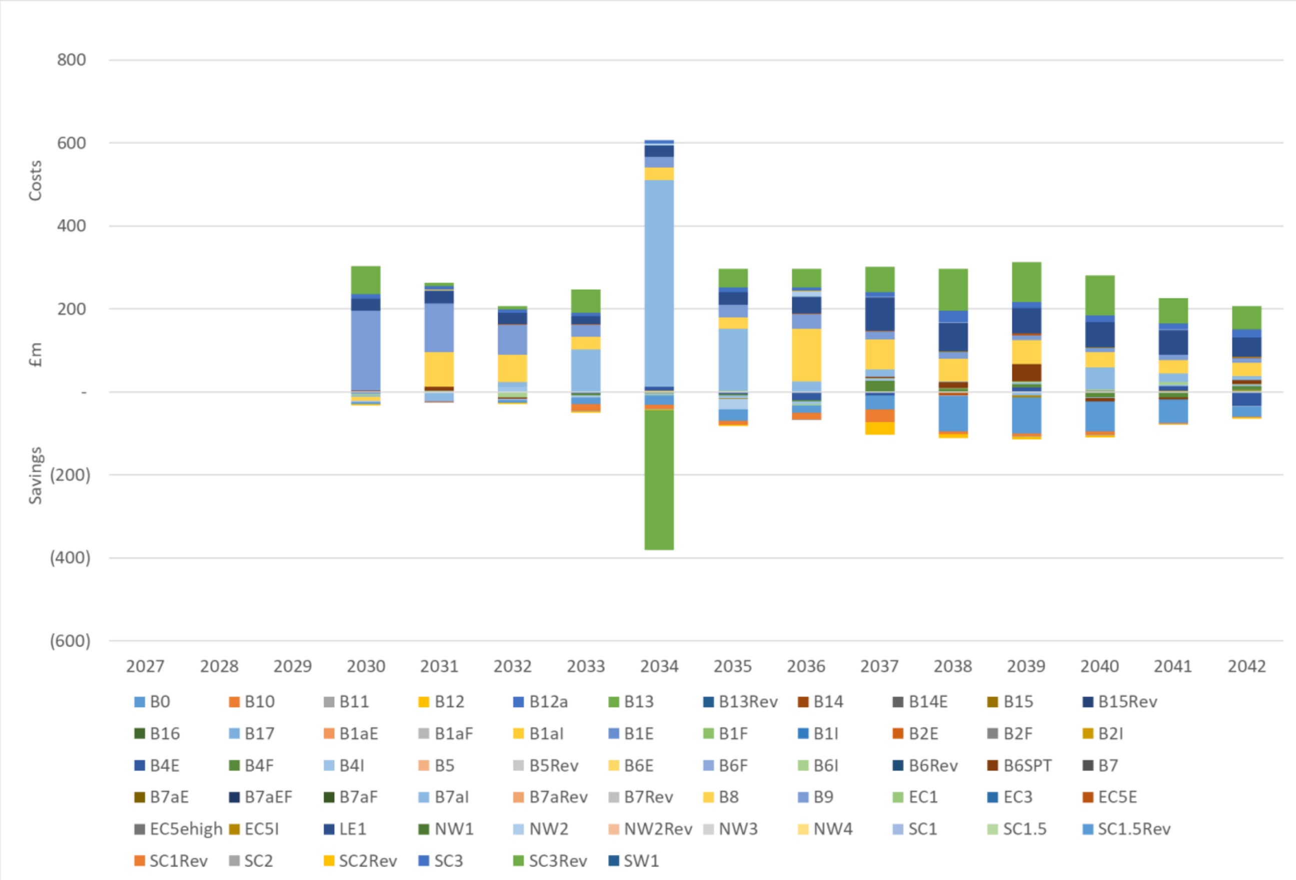


The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for Nautilus for the First Additional case for the Falling Short scenario.

In general, Nautilus increases constraint costs on several northern and southern boundaries but relieves congestion on several southern boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis, constraint costs are higher on various northern and southern boundaries.

Figure 220: Change in constraint costs by boundary for Nautilus for the Marginal Additional case for Leading the Way.



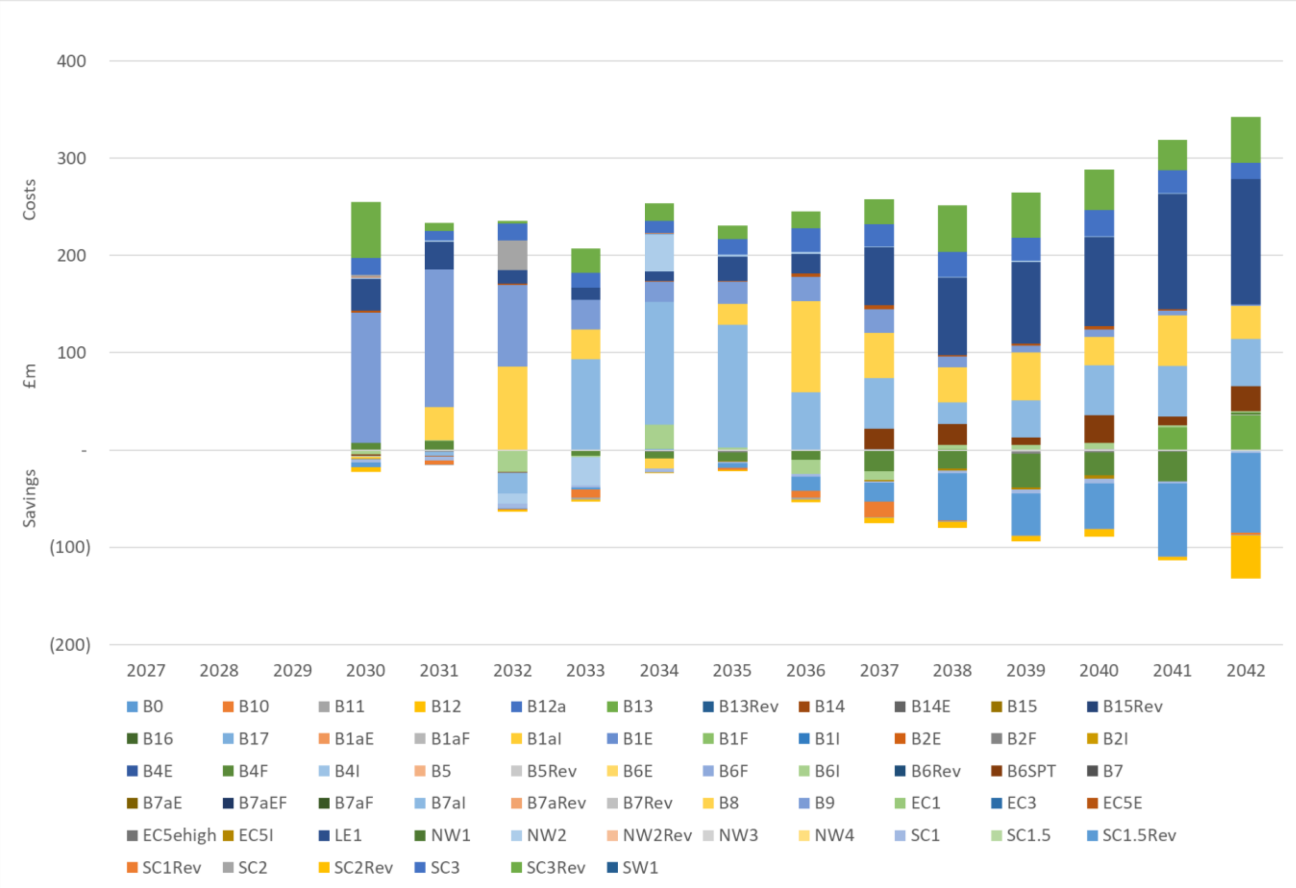
The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for Nautilus for the Marginal Additional case for the Leading the Way scenario.

In general, Nautilus increases constraint costs on several northern, midland and southern boundaries, but relieves congestion on various boundaries and one southern boundary in particular for one year. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Nautilus relieves significant congestion on one southern boundary in 2034. The saving only occurs for a single year suggesting the combination of supply, demand and boundary capabilities that enable such a significant saving across one boundary when Nautilus is included only exist for that year. That is in later years, supply and demand patterns and boundary capabilities will have evolved such that the model is no longer able to produce the lowest total cost solution by significantly reducing constraint costs across that particular boundary when Nautilus is included.

Compared to the original (March 2024) analysis, constraint costs are lower on various southern boundaries.

Figure 221: Change in constraint costs by boundary for Nautilus for the Marginal Additional case for Consumer Transformation.

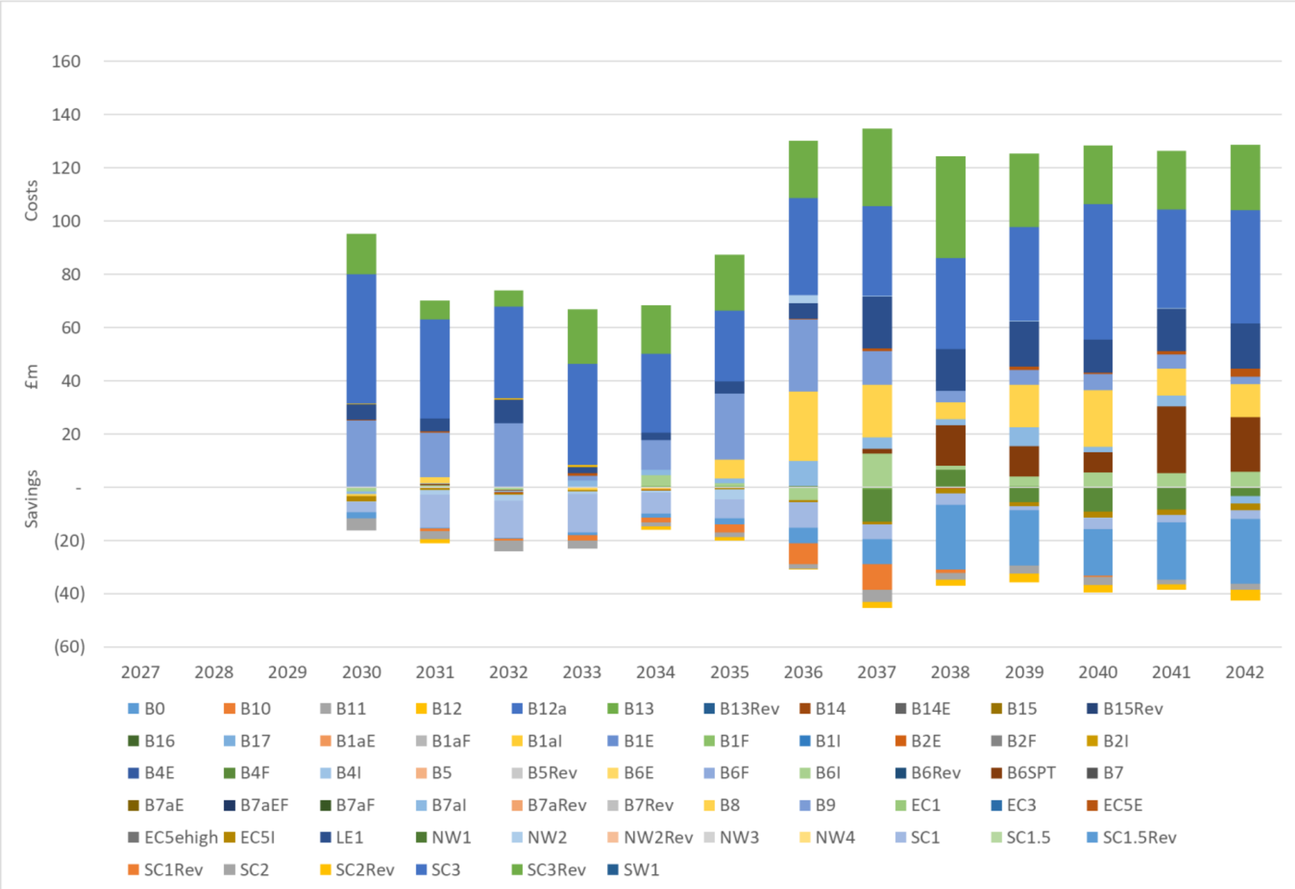


The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for Nautilus for the Marginal Additional case for the Consumer Transformation scenario.

In general, Nautilus increases constraint costs on several northern and southern boundaries but relieves congestion on certain southern boundaries in the later years. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis, constraint costs are lower on various northern and southern boundaries.

Figure 222: Change in constraint costs by boundary for Nautilus for the Marginal Additional case for Falling Short.



The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for Nautilus for the Marginal Additional case for the Falling Short scenario.

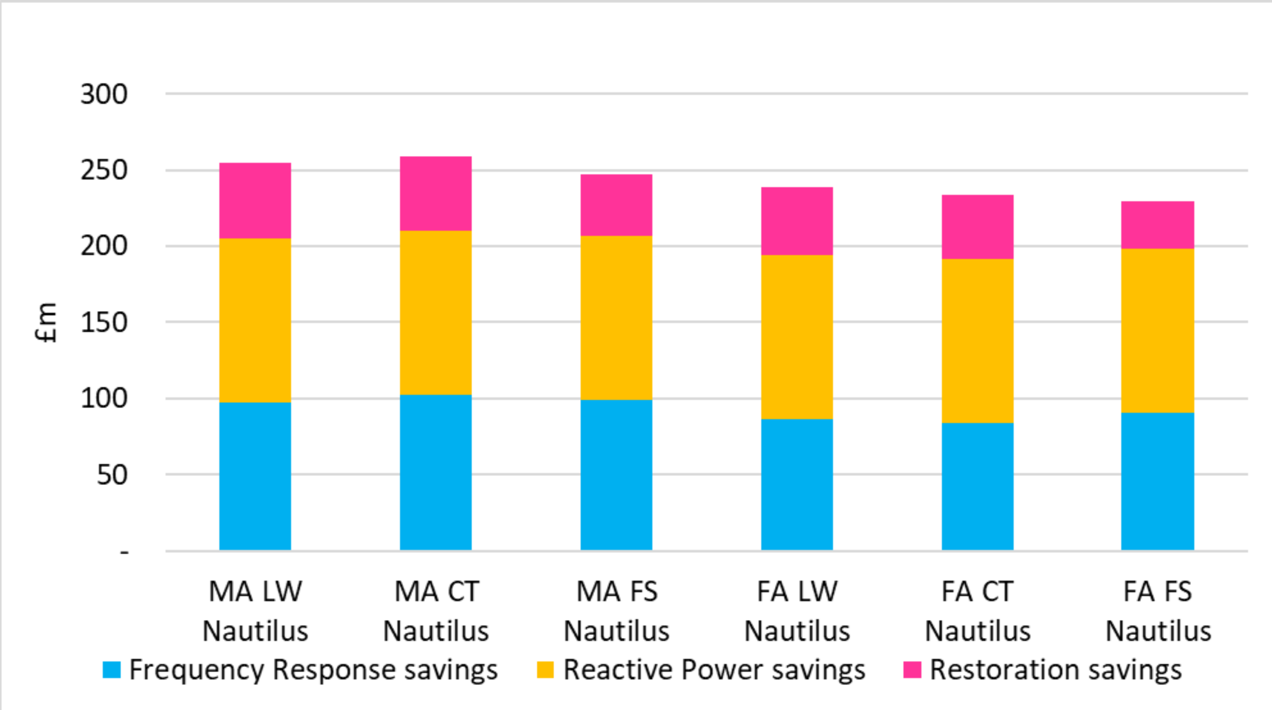
In general, Nautilus increases constraint costs on several northern and southern boundaries but relieves congestion on certain southern boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis, constraint costs are lower on various southern boundaries.

PV system operation

Note: The modelling and analysis for system operation is the same as that within the March 2024 report. It was not necessary to repeat the work because the change in modelling assumptions would not produce a material change in the results.

Figure 223: PV potential system operability savings for Nautilus, Present Value 25-year, real 2022, £m.

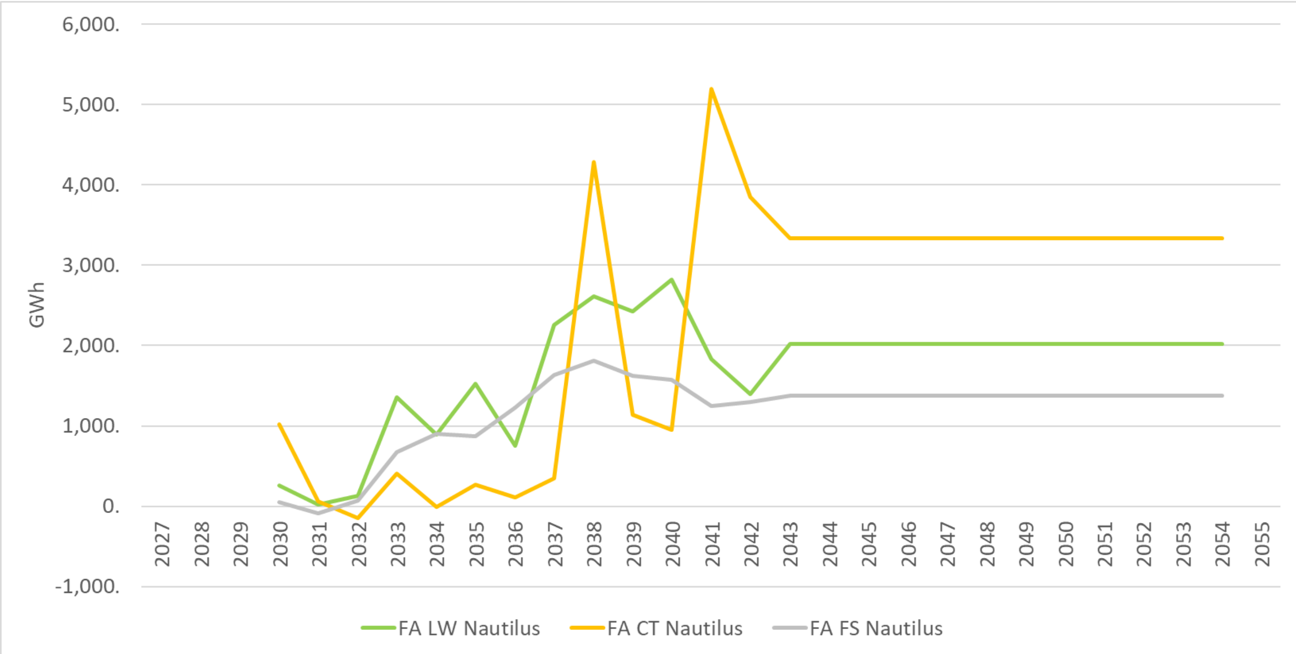


The above figure shows the potential savings for frequency response, reactive power and restoration services in present value (25-year, 2022 £m) for Nautilus for Leading the Way, Consumer Transformation and Falling Short for both the Marginal Additional and First Additional cases. There is considerable uncertainty around forecasting potential system operability benefits over a 25-year time horizon, but the figure shows that there is potentially significant savings in frequency response, reactive power and restoration services.

There is little variation across the three scenarios and also across the First Additional and Marginal Additional cases. This is because the potential system operability savings from the services provided by Nautilus are less sensitive to flows across the interconnector, whereas the constraint cost impact is highly dependent on the scale and direction of flows across the project.

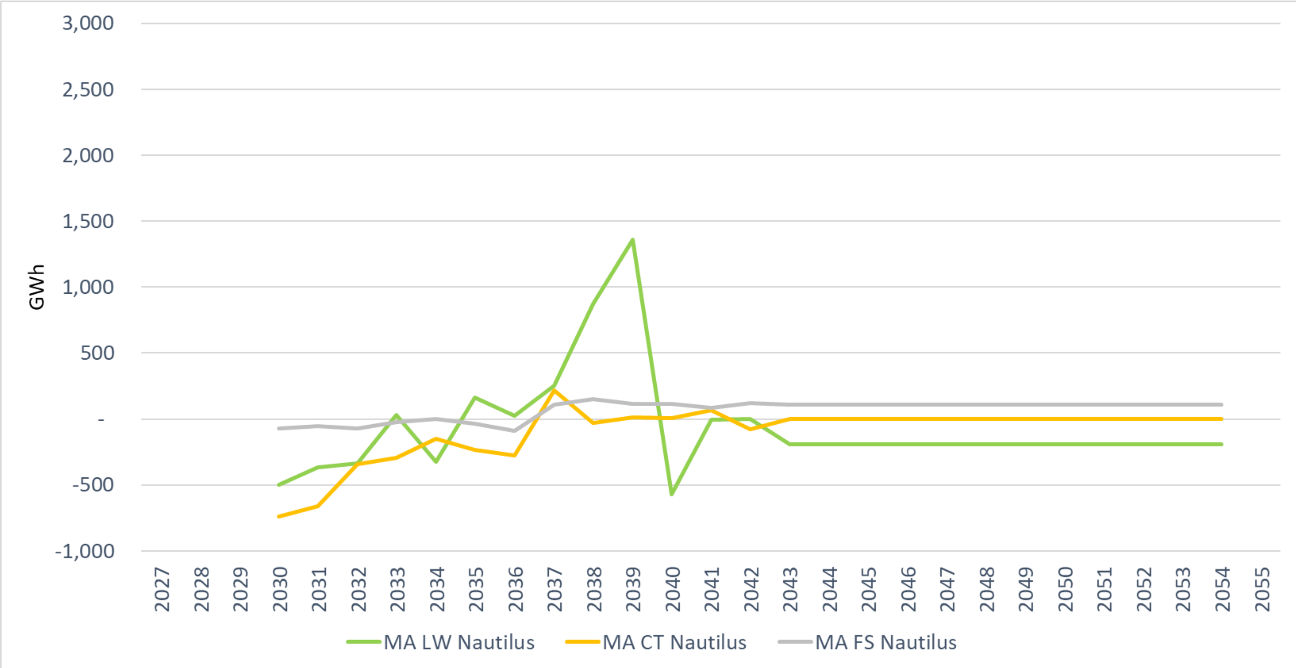
RES curtailment avoided

Figure 224: Annual RES curtailment avoided for Nautilus for the First Additional case.



The above figure shows the renewable energy supply (RES) curtailment avoided on an annual basis for Leading the Way, Consumer Transformation and Falling Short for the First Additional case. Note that beyond 2042, the results are an average of the years 2040, 2041 and 2042, as our detailed modelling with FES22 only extends out to 2042. The figure shows that the level of annual RES curtailment avoided when Nautilus is included is approximately between 0TWh and 3TWh, which equates to approximately between 0GWh and 8.2GWh per day.

Figure 225: Annual RES curtailment avoided for Nautilus for the Marginal Additional case.



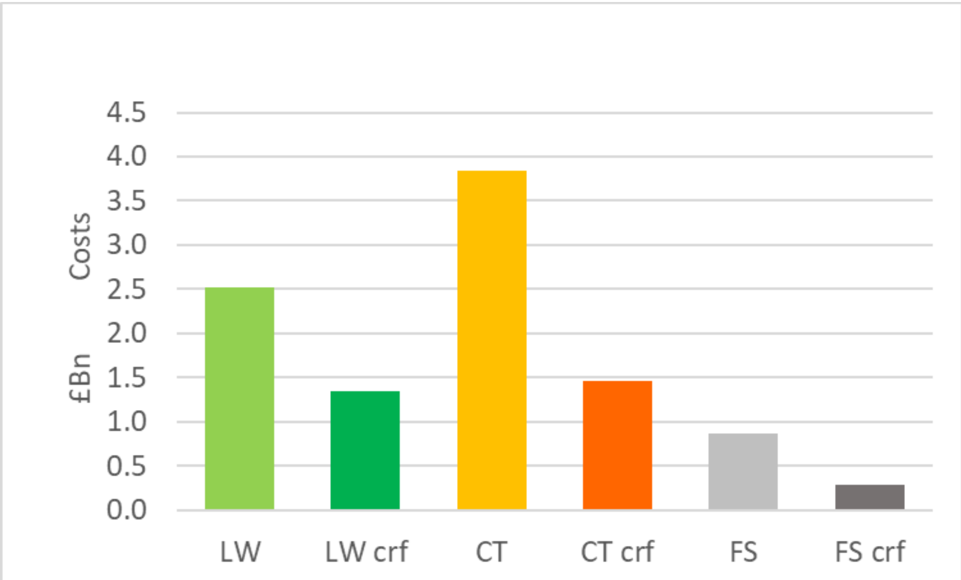
The above figure shows the renewable energy supply (RES) curtailment avoided on an annual basis for Leading the Way, Consumer Transformation and Falling Short for the Marginal Additional case. Note that beyond 2042, the results are an average of the years 2040, 2041 and 2042, as our detailed modelling with FES22 only extends out to 2042. The figure shows that the level of annual RES curtailment avoided when Nautilus is included rises to approximately between -0.5TWh and 0.25TWh, which equates to approximately between -1.4GWh and 0.7GWh per day.

17. NU-Link

NU-Link is a W3 interconnector project. It has a capacity of 1.2GW and connects to The Netherlands.

PV constraint costs

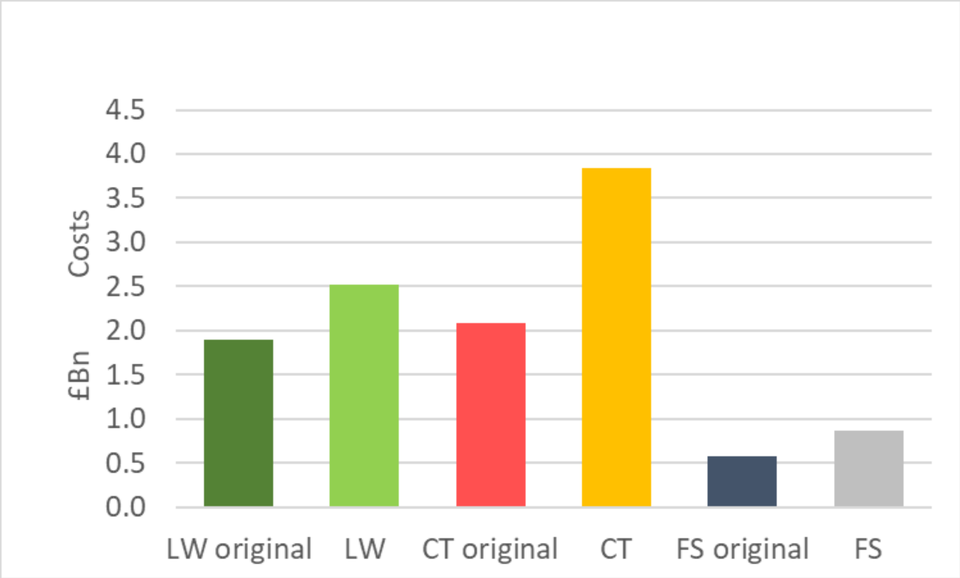
Figure 226: PV additional constraint costs due to NU-Link for the First Additional case, Present Value 25-year, real 2022, £m, without and with Constraint Reduction Factor applied.



The above figure shows the additional constraint costs with the inclusion of NU-Link for the FA case. Without the Constraint Reduction Factor applied, in the Leading the Way scenario (LW) constraint costs are increased by £2.5bn, in Consumer Transformation (CT) by £3.8bn and in the Falling Short (FS) scenario by £0.86bn.

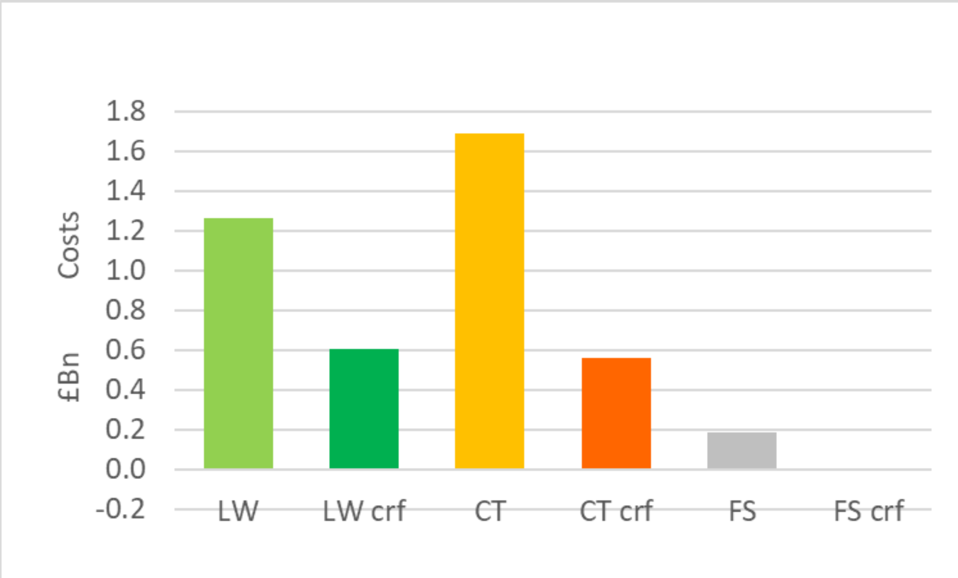
With the Constraint Reduction Factor applied, in the Leading the Way scenario (LW) constraint costs are increased by £1.3bn, in Consumer Transformation (CT) by £1.5bn and in the Falling Short (FS) scenario by £0.29bn.

Figure 227: PV additional constraint costs due to NU-Link for the First Additional case, Present Value 25-year, real 2022, £m, for the original analysis (March 2024) and for Nautilus at Grain with 1.4GW link and Irish demand and generation from TYNDP.



The above figure shows that the changes made to the scenarios, that is the reduction in the capacity of the link connecting the Nautilus offshore platform to Belgium from 3.5GW to 1.4GW and the change in Irish demand and generation to reflect final TYNDP data results in an increase in constraint costs in all three scenarios, particularly in CT.

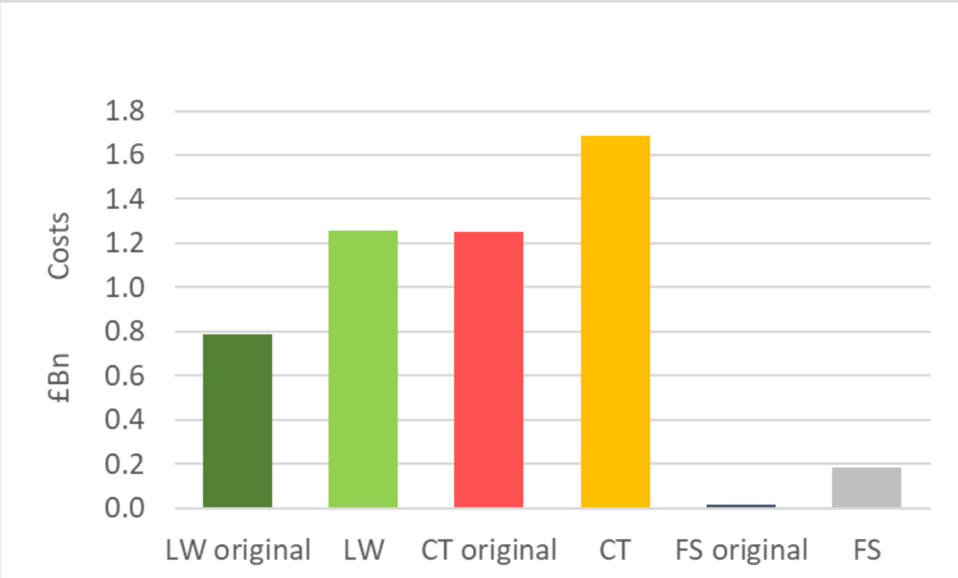
Figure 228: PV additional constraint costs due to NU-Link for the Marginal Additional case, Present Value 25-year, real 2022, £m, without and with Constraint Reduction Factor applied.



The above figure shows the additional constraint costs with the inclusion of NU-Link for the MA case. Without the Constraint Reduction Factor applied, in the Leading the Way scenario (LW) constraint costs are increased by £1.3bn, in Consumer Transformation (CT) by £1.7bn and in the Falling Short scenario (FS) by £0.18bn.

With the Constraint Reduction Factor applied, in the Leading the Way scenario (LW) constraint costs are increased by £0.6bn, in Consumer Transformation (CT) by £0.56bn and in the Falling Short (FS) scenario constraint costs are reduced by £0.01bn.

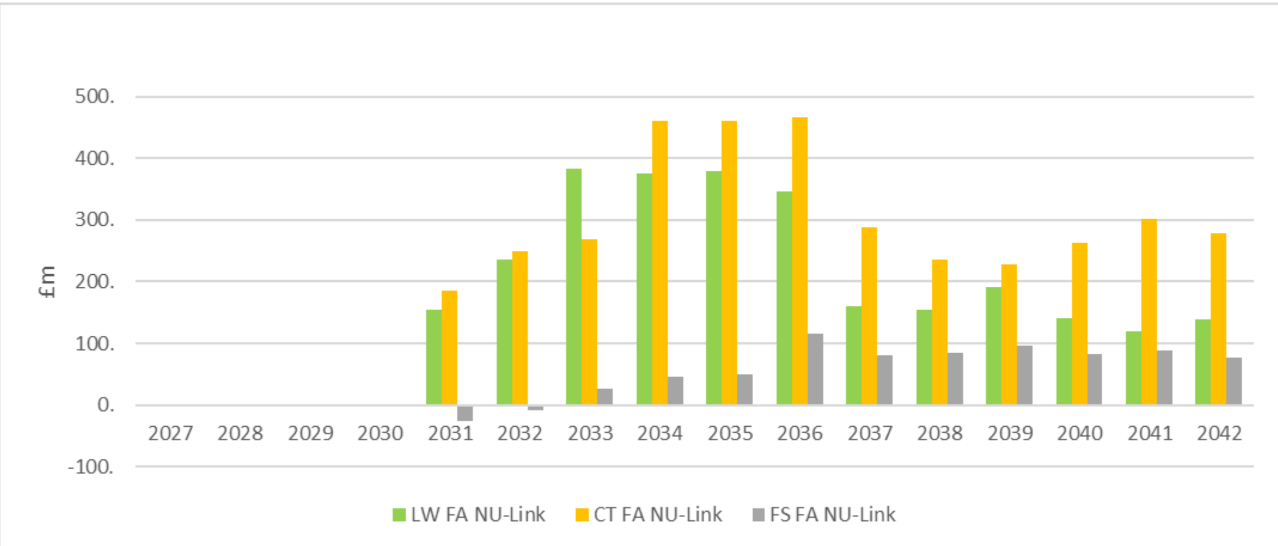
Figure 229: PV additional constraint costs due to NU-Link for the Marginal Additional case, Present Value 25-year, real 2022, £m, for the original analysis (March 2024) and for Nautilus at Grain with 1.4GW link and Irish demand and generation from TYNDP.



The above figure shows that the changes made to the scenarios, that is the reduction in the capacity of the link connecting the Nautilus offshore platform to Belgium from 3.5GW to 1.4GW and the change in Irish demand and generation to reflect final TYNDP data results in a significant increase in constraint costs in all three scenarios.

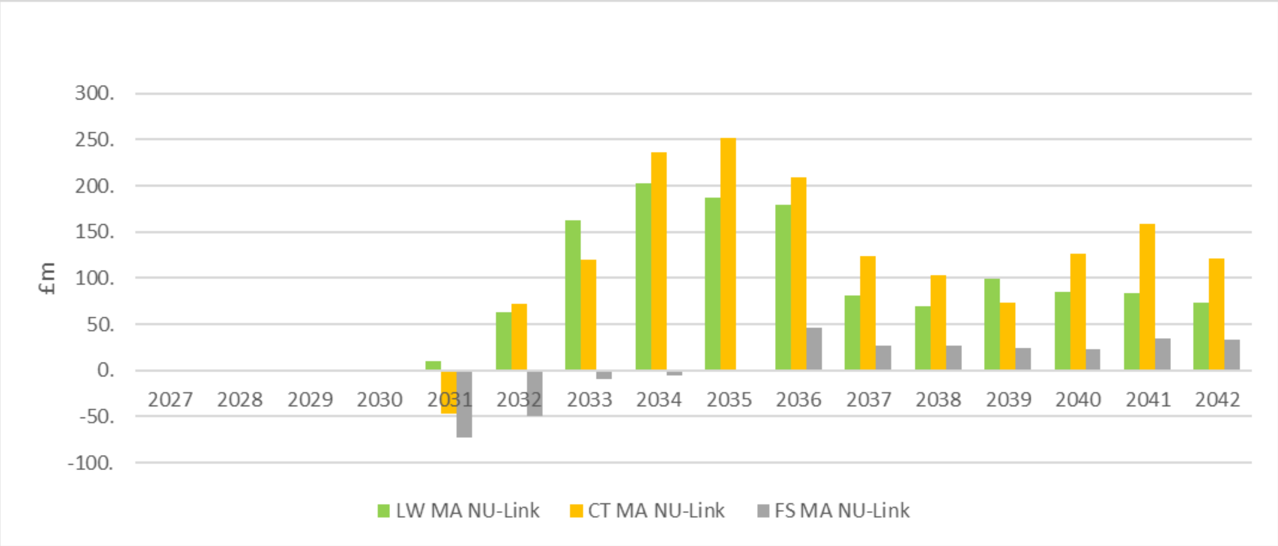
Annual constraint costs (undiscounted)

Figure 230: Additional annual constraint costs (undiscounted) due to NU-Link for the First Additional case.



The above figure shows that NU-Link results in an increase in constraint costs of approximately £200m to £450m (undiscounted) in CT and LW for the years 2032 to 2036. In FS constraint cost increases are lower, with small savings in 2031 and 2032. The results are higher than the original (March 2024) results, particularly for CT.

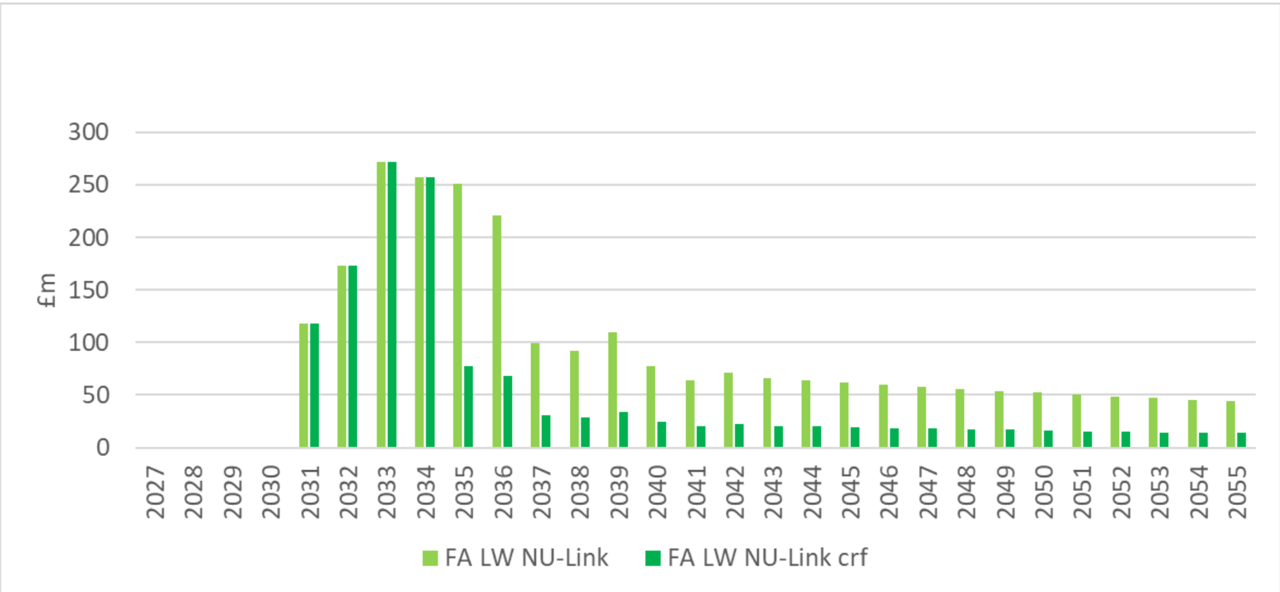
Figure 231: Additional annual constraint costs (undiscounted) due to NU-Link for the Marginal Additional case.



In the Marginal Additional case, NU-Link results in an increase in constraint costs of approximately £100m to £250m (undiscounted) in CT and LW for the years 2033 to 2036. FS shows constraint savings for the years 2033 to 2035, and for the other years shows lower levels of additional constraint costs compared to LW and CT. The results are higher than the original (March 2024) results.

Annual constraint costs (discounted), without and with Constraint Reduction Factor

Figure 232: Additional annual constraint costs (discounted) due to NU-Link for the First Additional case for Leading the Way, without and with Constraint Reduction Factor applied.



The above chart shows the additional constraint costs without and with the Constraint Reduction Factor (CRF) applied for the Leading the Way scenario for the First Additional case. The chart shows the impact of the CRF being applied from 2035 onwards.

Figure 233: Additional annual constraint costs (discounted) due to NU-Link for the First Additional case for Consumer Transformation, without and with Constraint Reduction Factor applied.

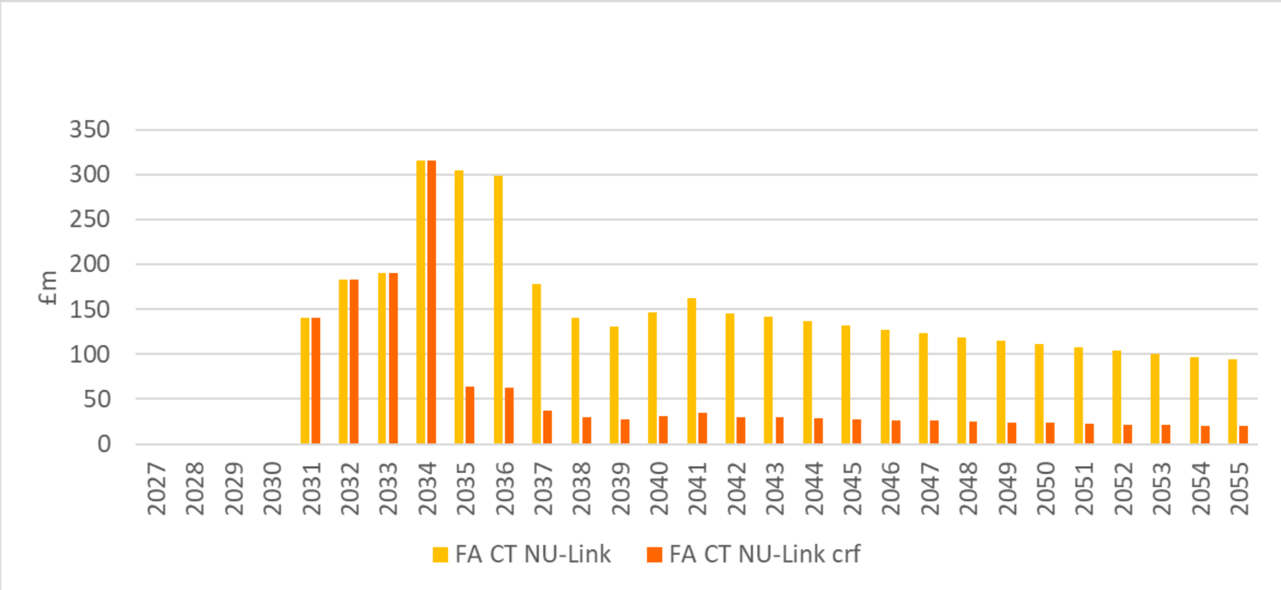
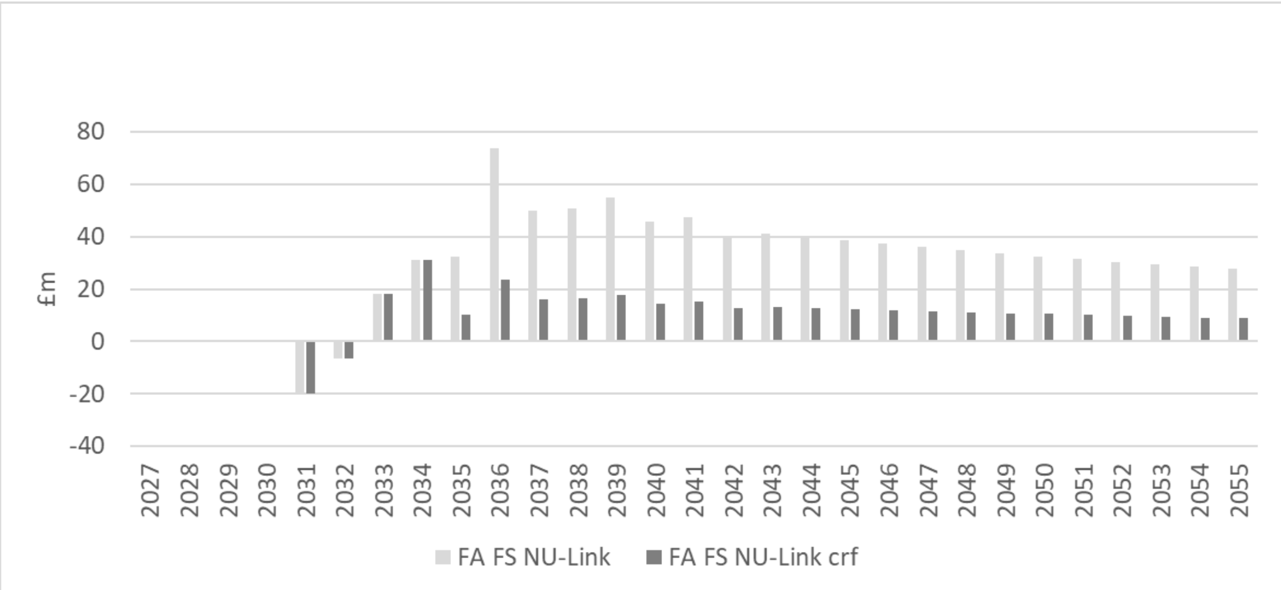
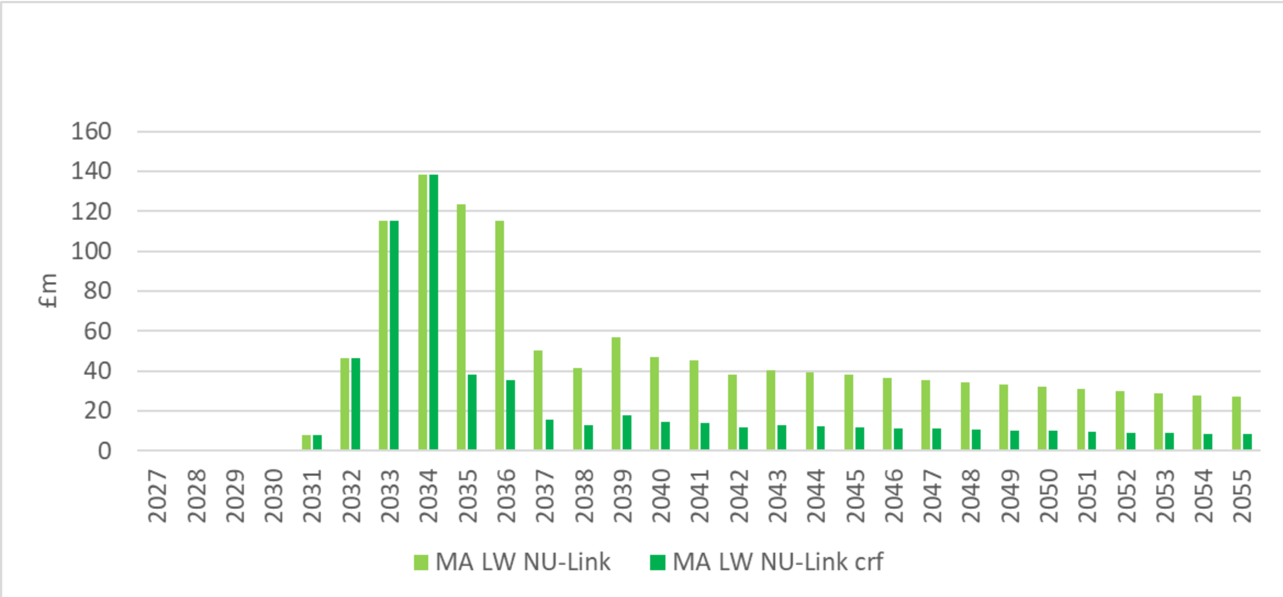


Figure 234: Additional annual constraint costs (discounted) due to NU-Link for the First Additional case for Falling Short, without and with Constraint Reduction Factor applied.



The above chart shows the additional constraint costs without and with the Constraint Reduction Factor (CRF) applied. The chart shows the impact of the CRF being applied from 2035 onwards. As the years prior to 2035 show relatively lower additional constraint costs than those after 2035, the impact of the CRF is more pronounced than for the Leading the Way scenario.

Figure 235: Additional annual constraint costs (discounted) due to NU-Link for the Marginal Additional case for Leading the Way, without and with Constraint Reduction Factor applied.



The above chart shows the additional constraint costs without and with the Constraint Reduction Factor (CRF) applied for the Leading the Way scenario for the Marginal Additional case. The chart shows the impact of the CRF being applied from 2035 onwards.

Figure 236: Additional annual constraint costs (discounted) due to NU-Link for the Marginal Additional case for Consumer Transformation, without and with Constraint Reduction Factor applied.

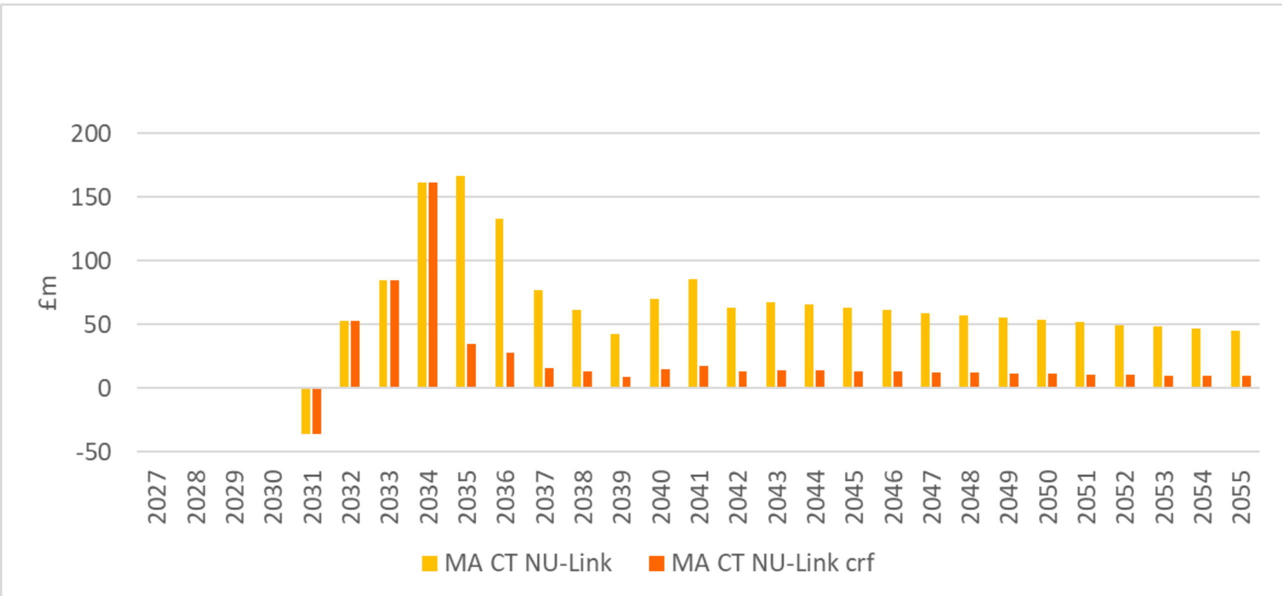
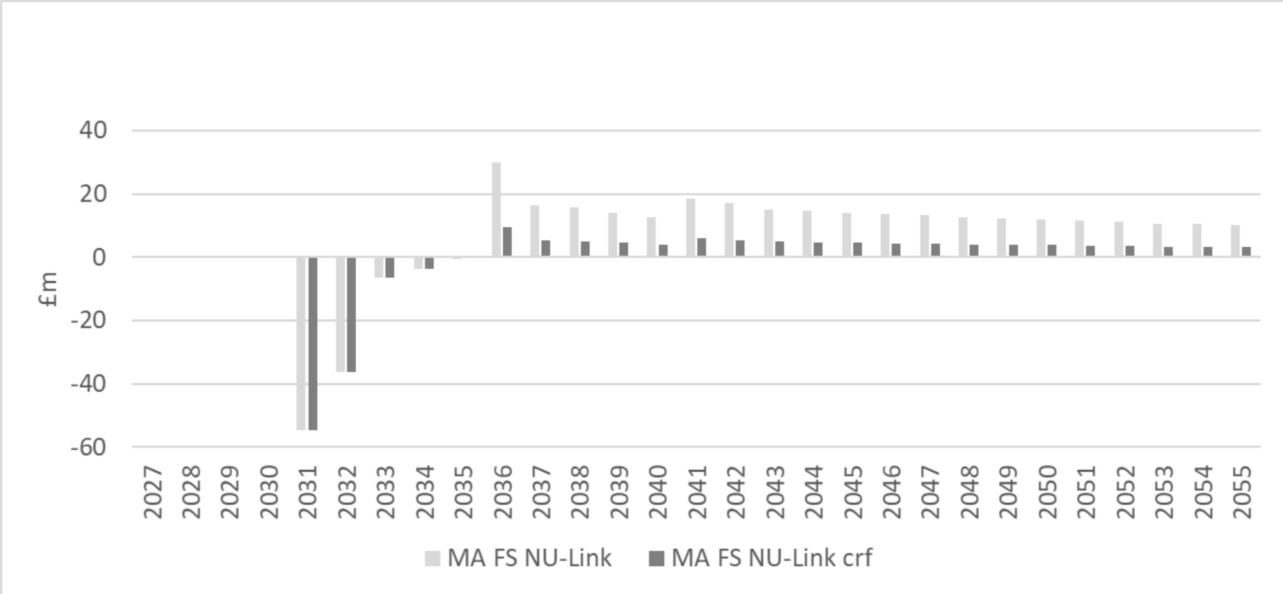
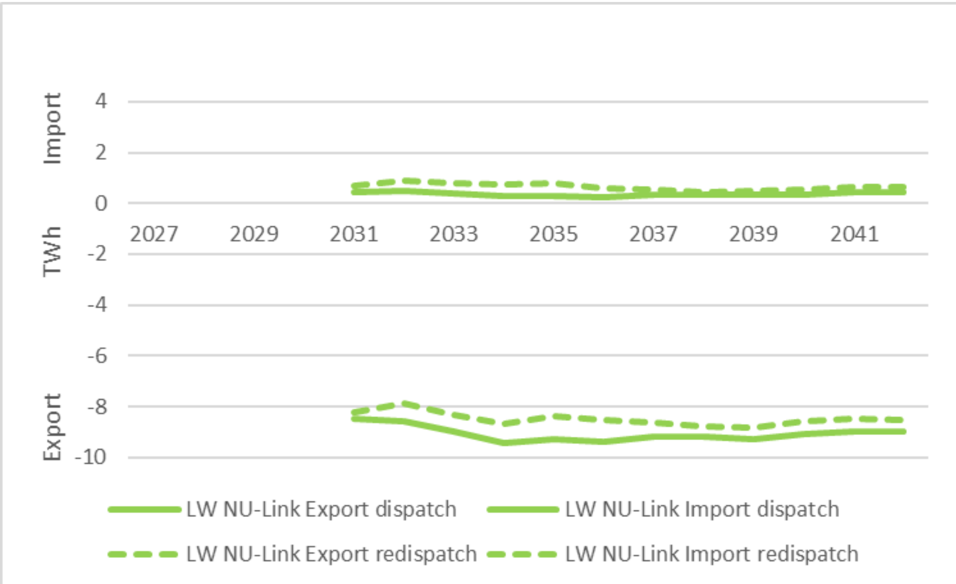


Figure 237: Additional annual constraint costs (discounted) due to NU-Link for the Marginal Additional case for Falling Short, without and with Constraint Reduction Factor applied.



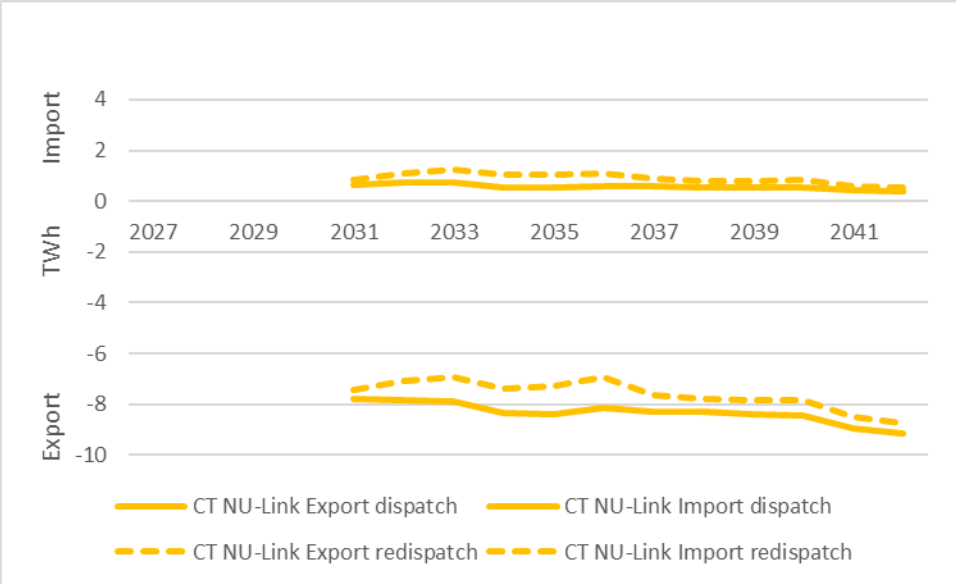
Annual import and export flows for dispatch and redispatch

Figure 238: Annual import and export flows for NU-Link in the FA case for Leading the Way.



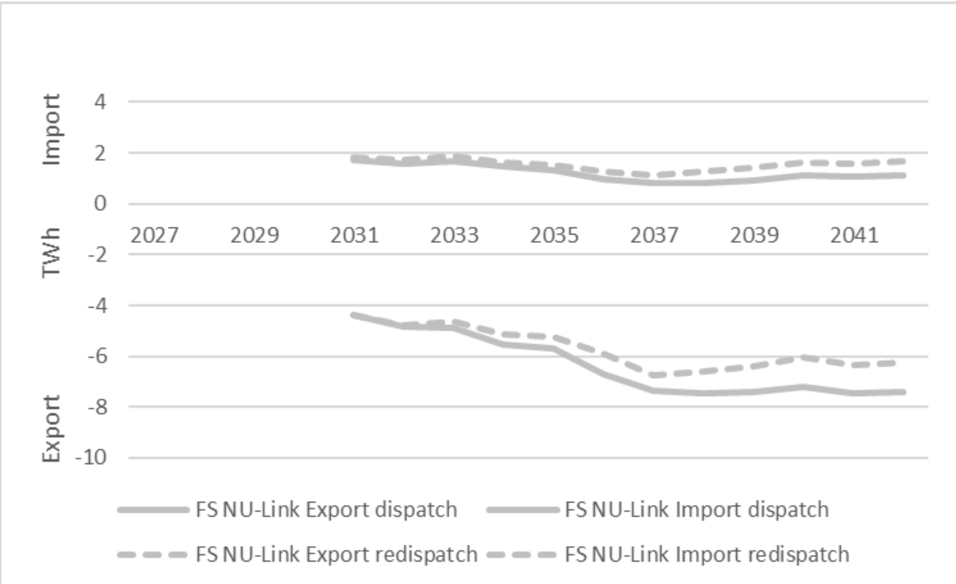
The above figure shows high exports and low imports in the dispatch. The redispatch shows a reduction in exports and a very slight increase in imports. Compared to the original (March 2024) results, exports and imports are very similar.

Figure 239: Annual import and export flows for NU-Link in the FA case for Consumer Transformation.



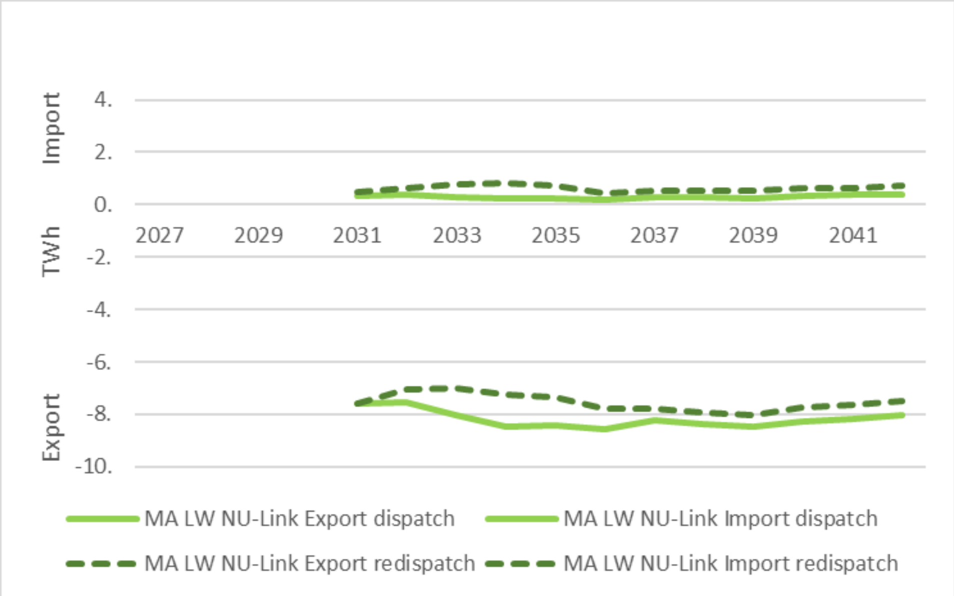
The above figure shows high exports and low imports in the dispatch. The redispatch shows a reduction in exports and a slight increase in imports. Compared to the original (March 2024) results, exports and imports are very similar.

Figure 240: Annual import and export flows for NU-Link in the FA case for Falling Short.



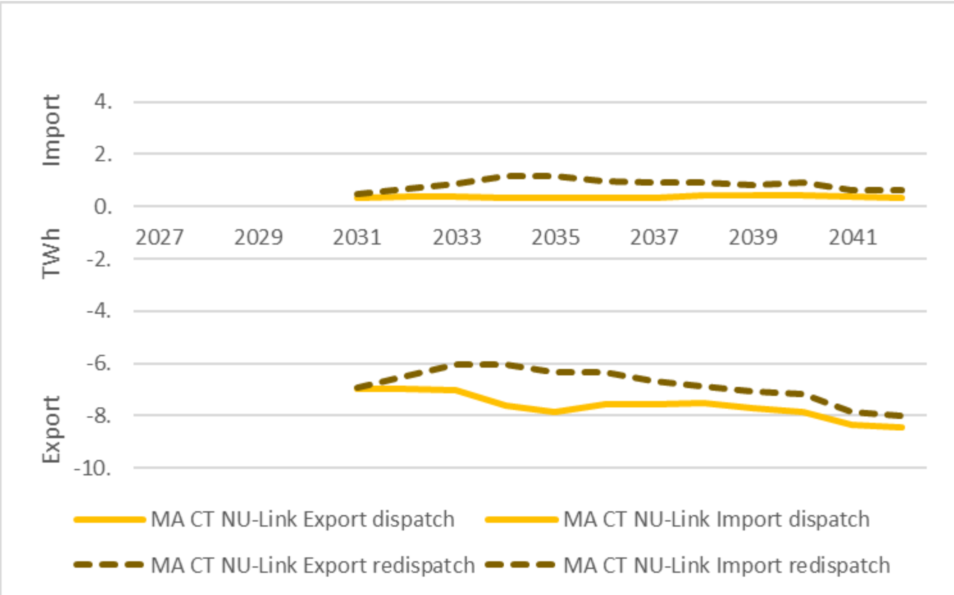
The above figure shows that for the First Additional case NU-Link has increasing levels of exports over the forecast period up to 2037 for Falling Short. Imports are relatively low. The redispatch shows a reduction in exports after 2033. Compared to the original (March 2024) results, exports and imports are very similar.

Figure 241: Annual import and export flows for NU-Link in the MA case for Leading the Way.



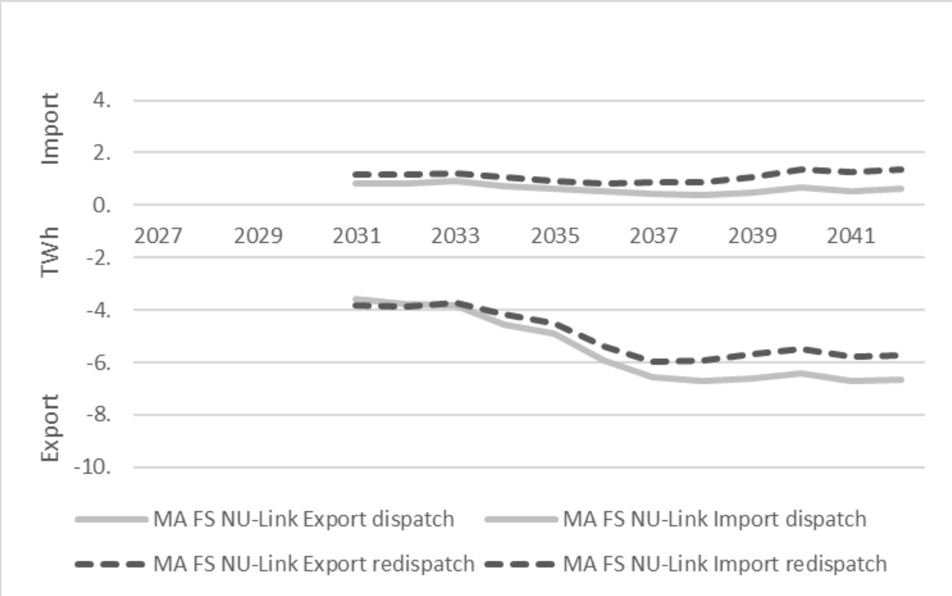
The above figure shows for the dispatch high exports and low imports. The redispatch shows a reduction in exports and a slight increase in imports. Compared to the original (March 2024) results, exports are slightly higher and imports are very similar.

Figure 242: Annual import and export flows for NU-Link in the MA case for Consumer Transformation.



The above figure shows high exports and low imports in the dispatch. The redispatch shows exports reduced significantly in the early to mid-2030s and an increase in imports. Compared to the original (March 2024) results, exports are slightly higher and imports are very similar.

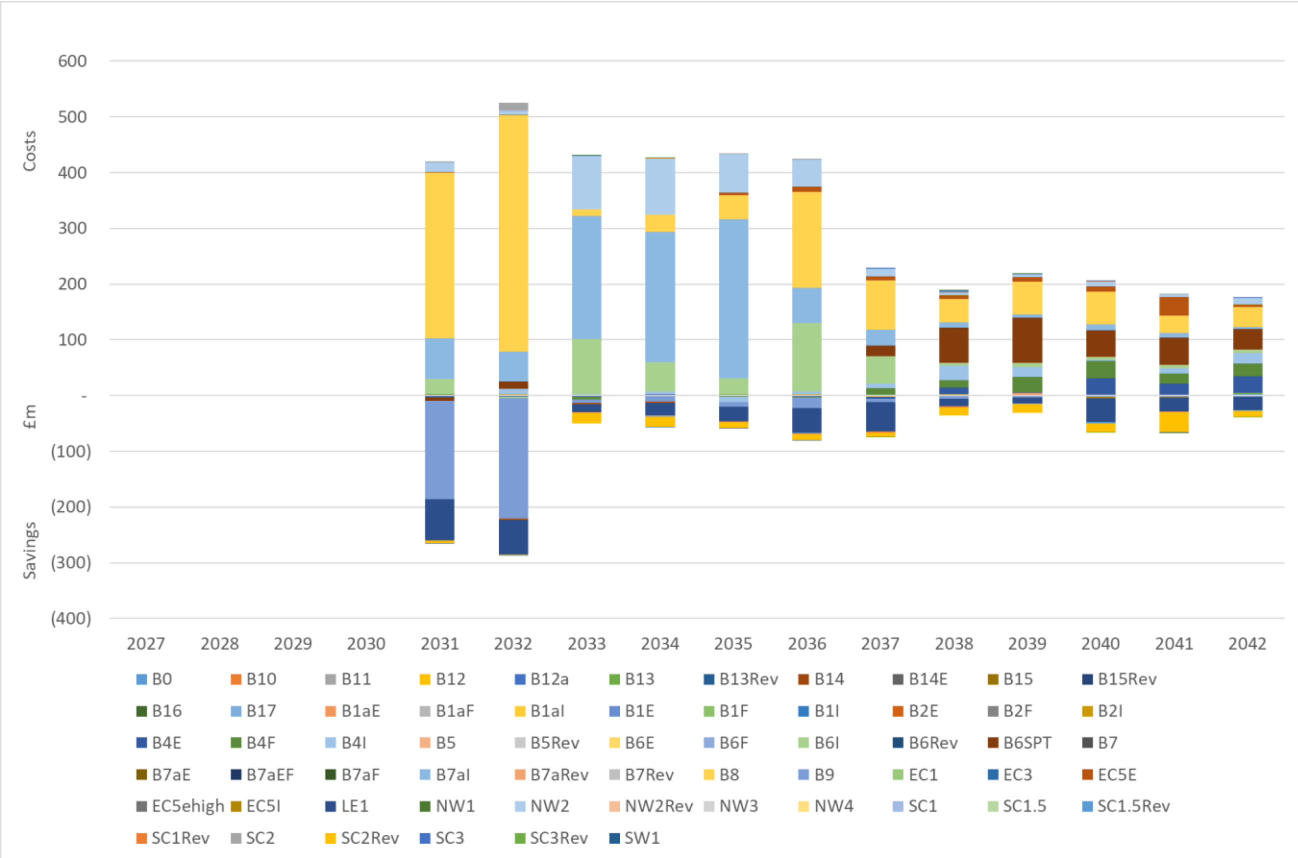
Figure 243: Annual import and export flows for NU-Link in the MA case for Falling Short.



The above figure shows that for the Marginal Additional case, NU-Link has increasing exports and low imports in the dispatch. The redispatch shows a slight reduction in exports, especially in the later years and a small increase in imports. Compared to the original (March 2024) results, exports and imports are very similar.

Change in constraint costs by boundary

Figure 244: Change in constraint costs by boundary for NU-Link for the First Additional case for Leading the Way.



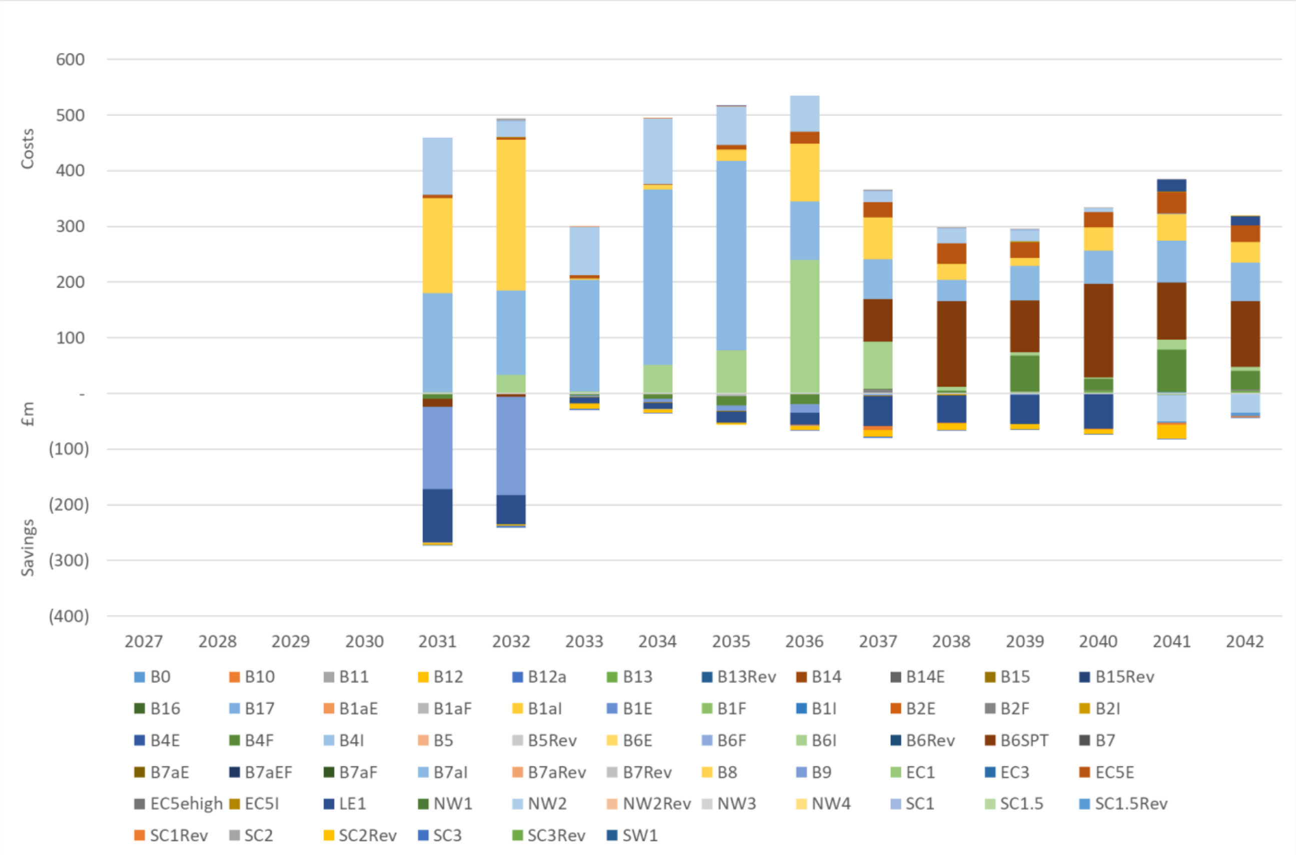
The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for NU-Link for the First Additional case for the Leading the Way scenario. Each different colour represents the change in constraint costs for a particular boundary. It is important to note that the chart shows changes in constraint costs by boundary, i.e. the difference between constraint costs when the project is included and when the project is excluded.

The figure shows that NU-Link increases constraint costs on certain boundaries but also reduces constraint costs on others. Whether the impact is an increase in constraint costs or a reduction in constraint costs for a particular boundary, changes from year to year. The size of change in constraint costs by boundary can also vary significantly from year to year. This is shown clearly in the years 2035 to 2036. The figure also shows that the specific boundaries that have the greatest impact on the total change in constraint costs can vary from year to year. These factors are a result of the changes in demand, supply and network capability over time.

In general, NU-Link increases constraint costs on several northern boundaries but relieves congestion on certain other midland and southern boundaries particularly in the early years. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis constraint costs are higher on several northern boundaries.

Figure 245: Change in constraint costs by boundary for NU-Link for the First Additional case for Consumer Transformation.

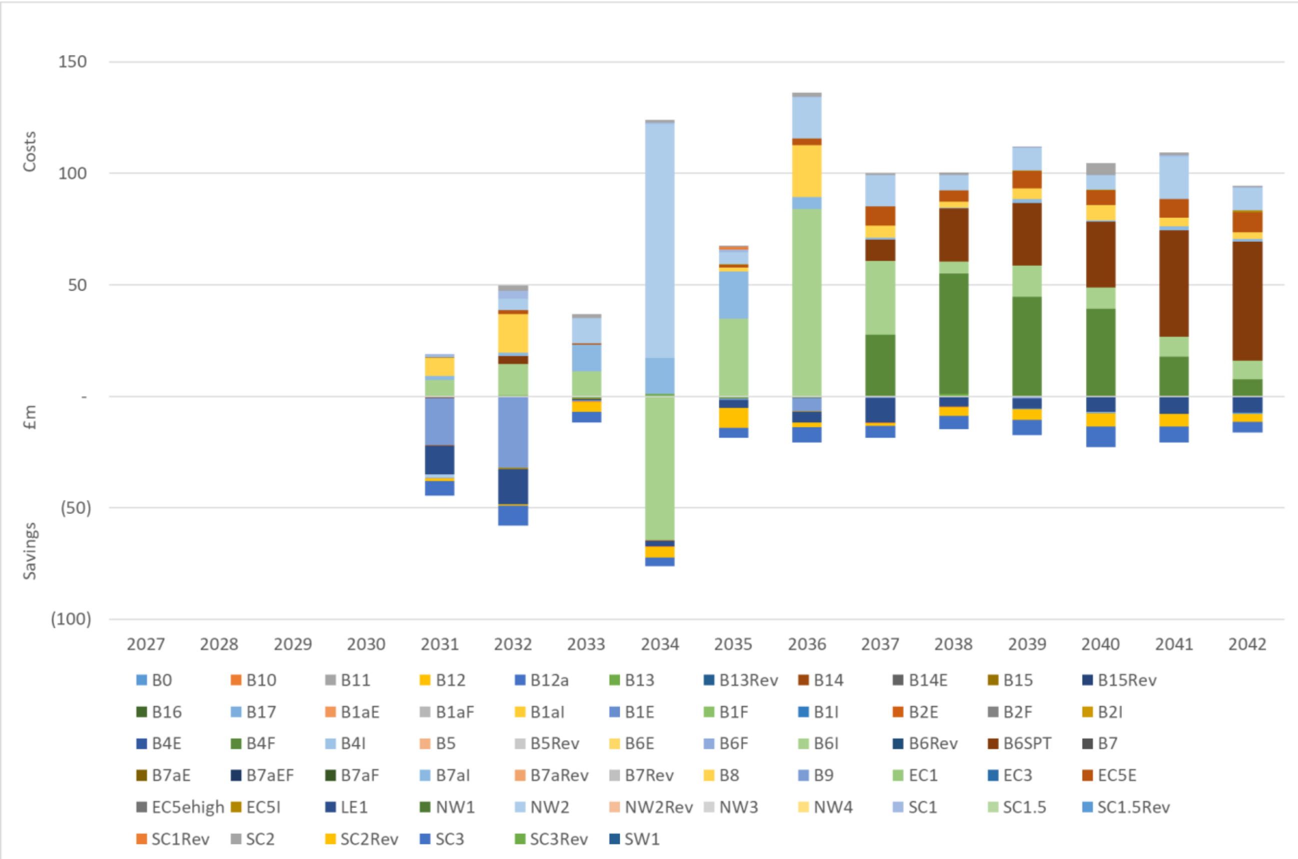


The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for NU-Link for the First Additional case for the Consumer Transformation scenario.

In general, NU-Link increases constraint costs on several northern boundaries but relieves congestion on certain midland and southern boundaries particularly in the early years. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis, constraint costs are higher on several northern boundaries.

Figure 246: Change in constraint costs by boundary for NU-Link for the First Additional case for Falling Short.



The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for NU-Link for the First Additional case for the Falling Short scenario.

In general, NU-Link increases constraint costs on several northern boundaries and one Welsh boundary for one particular year but relieves congestion on certain midland boundaries in the early years. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis, constraint costs are higher on several northern boundaries and one Welsh boundary.

Figure 247: Change in constraint costs by boundary for NU-Link for the Marginal Additional case for Leading the Way.

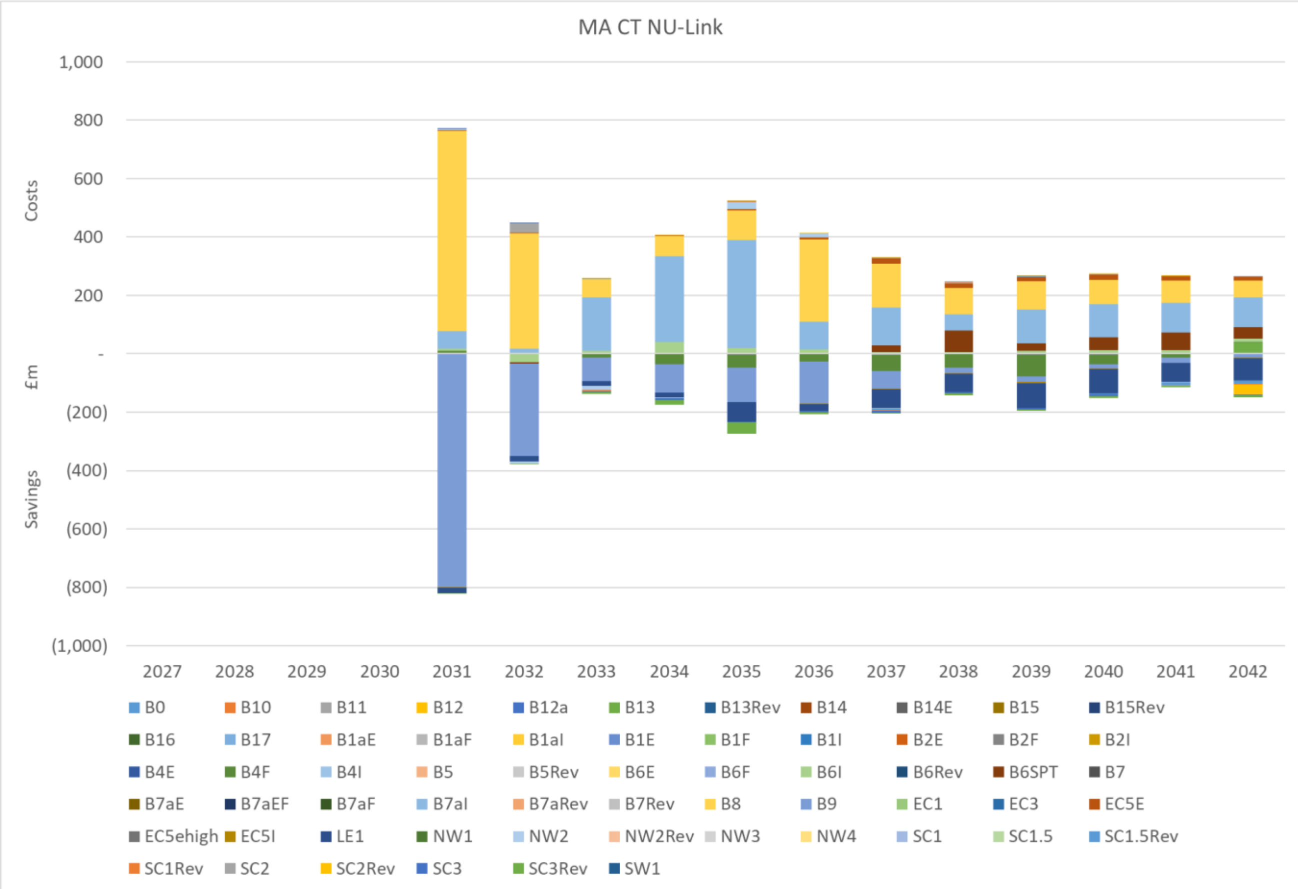
The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for NU-Link for the Marginal Additional case for the Leading the Way scenario.

In general, NU-Link increases constraint costs on northern and midland boundaries, but also relieves congestion on another midland boundary and several southern boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

NU-link relieves significant congestion on one midland boundary in 2031. The saving only occurs for a single year suggesting the combination of supply, demand and boundary capabilities that enable such a significant saving across one boundary when NU-Link is included only exist for that year. That is in later years, supply and demand patterns and boundary capabilities will have evolved such that the model is no longer able to produce the lowest total cost solution by significantly reducing constraint costs across that particular boundary when NU-Link is included.

Compared to the original (March 2024) analysis, constraint costs are higher on several northern boundaries.

Figure 248: Change in constraint costs by boundary for NU-Link for the Marginal Additional case for Consumer Transformation.



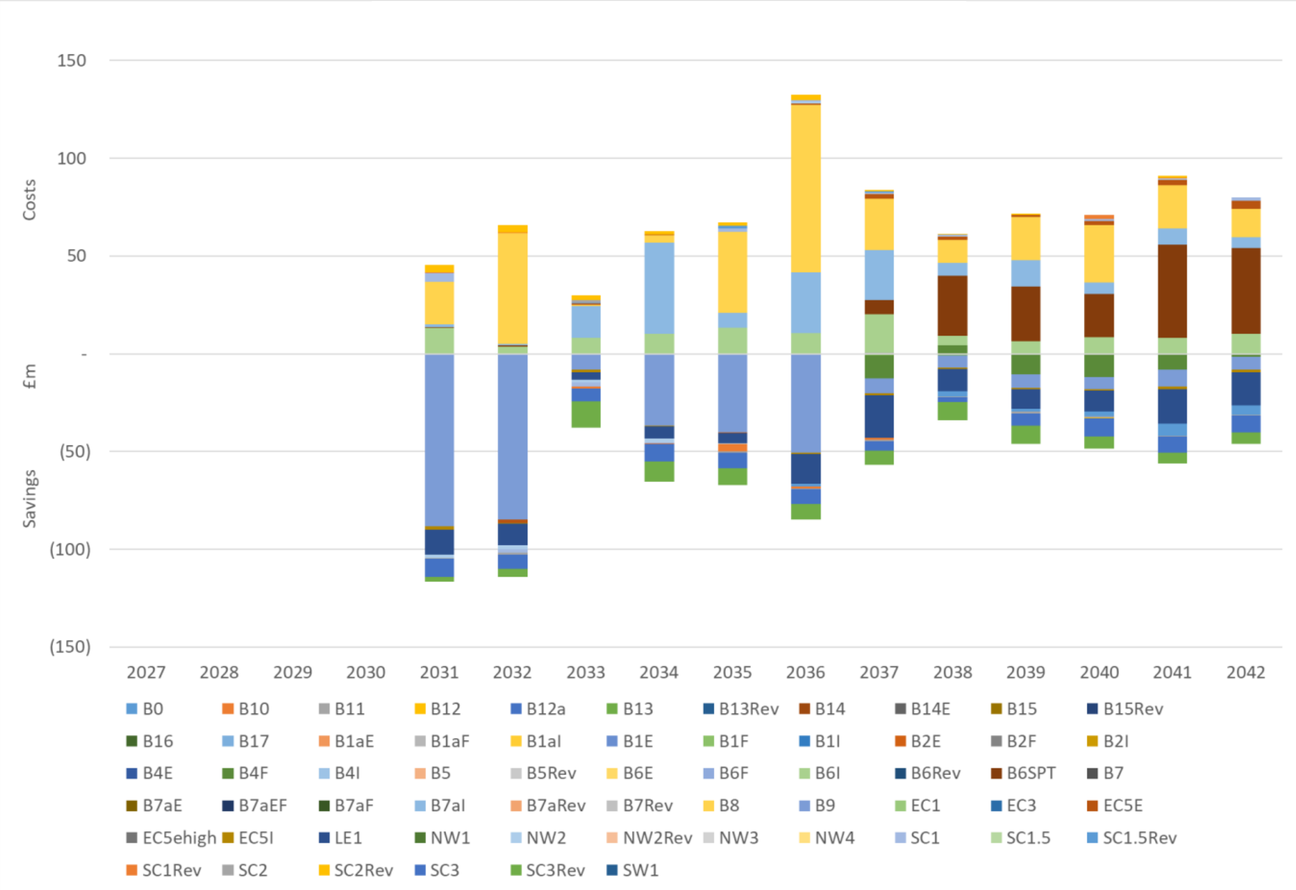
The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for NU-Link for the Marginal Additional case for the Consumer Transformation scenario.

In general, NU-Link increases constraint costs on northern and midland boundaries, but also relieves congestion on another midland boundary and several southern boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

NU-Link relieves significant congestion on one midland boundary in 2031. The saving only occurs for a single year suggesting the combination of supply, demand and boundary capabilities that enable such a significant saving across one boundary when NU-Link is included only exist for that year. That is in later years, supply and demand patterns and boundary capabilities will have evolved such that the model is no longer able to produce the lowest total cost solution by significantly reducing constraint costs across that particular boundary when NU-Link is included.

Compared to the original (March 2024) analysis, constraint costs are higher on several northern boundaries.

Figure 249: Change in constraint costs by boundary for NU-Link for the Marginal Additional case for Falling Short.



The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for NU-Link for the Marginal Additional case for the Falling Short scenario.

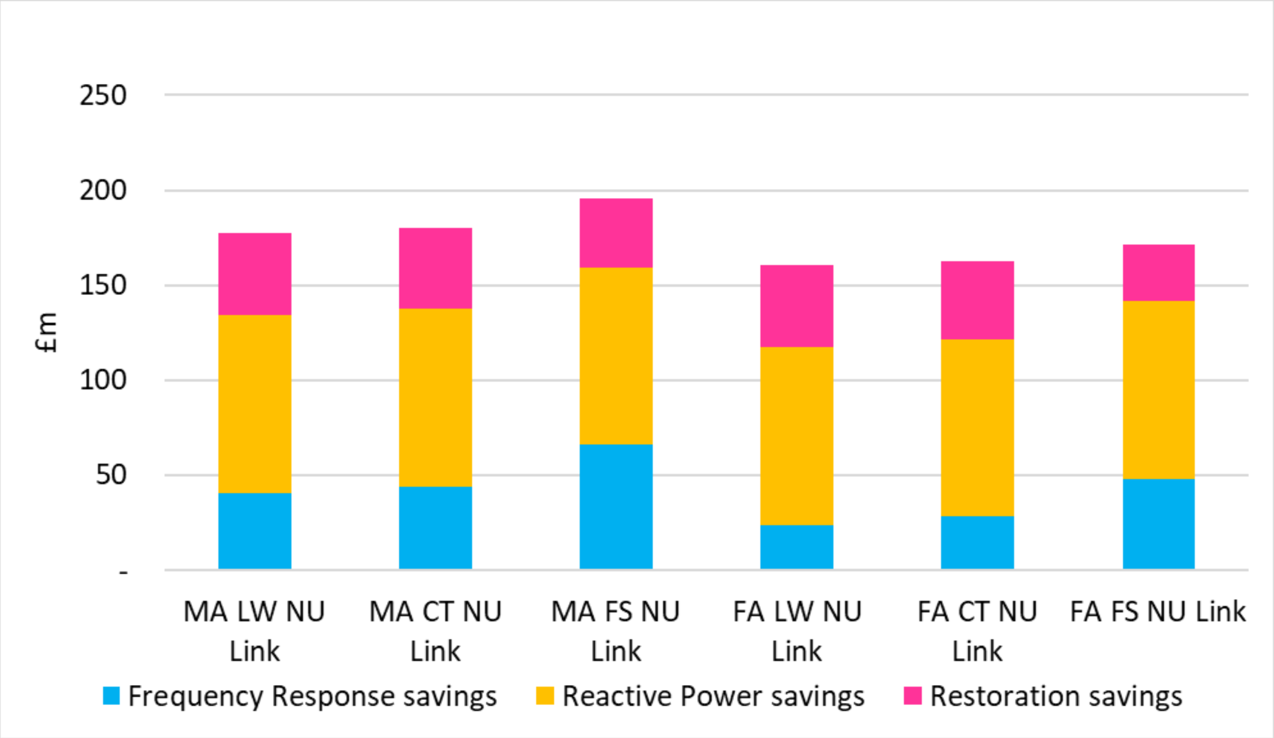
In general, NU-Link increases constraint costs on northern and midland boundaries, but also relieves congestion on another midland boundary and several southern boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis, constraint costs are higher on several northern boundaries.

PV system operation

Note: The modelling and analysis for system operation is the same as that within the March 2024 report. It was not necessary to repeat the work because the change in modelling assumptions would not produce a material change in the results.

Figure 250: PV potential system operability savings for NU-Link, Present Value 25-year, real 2022, £m.

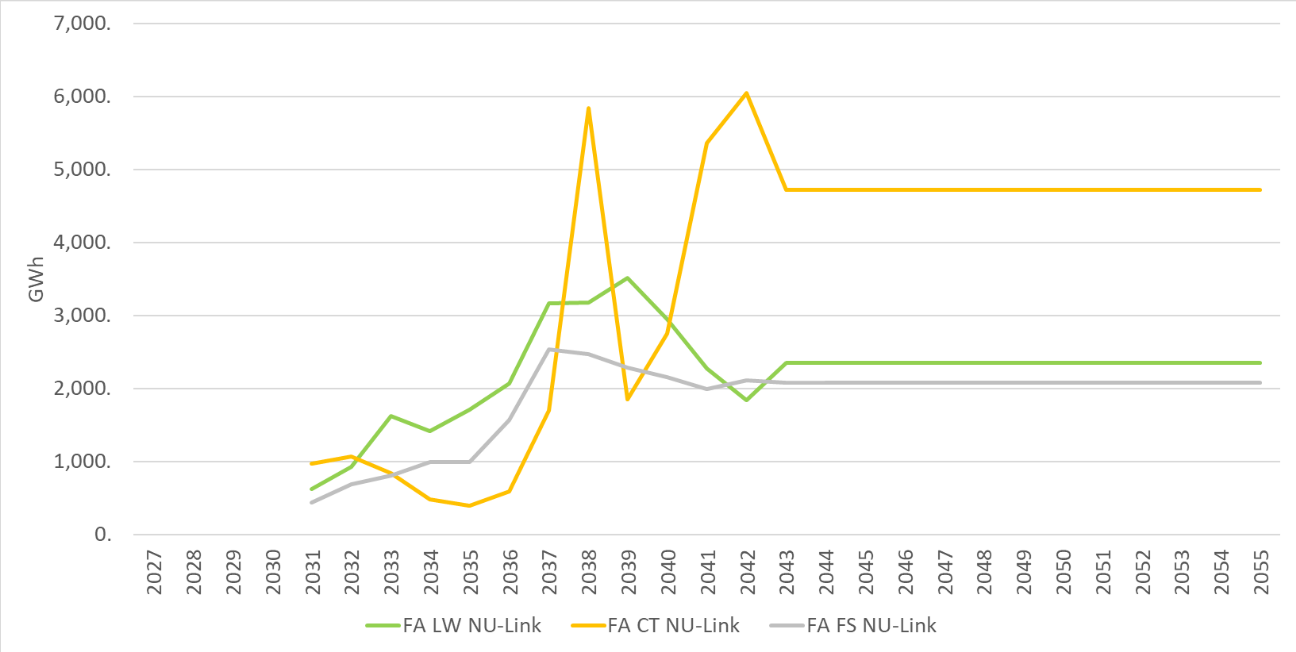


The above figure shows the potential savings for frequency response, reactive power and restoration services in present value (25-year, 2022 £m) for NU-Link for Leading the Way, Consumer Transformation and Falling Short for both the Marginal Additional and First Additional cases. There is considerable uncertainty around forecasting potential system operability benefits over a 25-year time horizon, but the figure shows that there is potentially significant savings in frequency response, reactive power and restoration services.

There is little variation across the three scenarios and also across the First Additional and Marginal Additional cases. This is because the potential system operability savings from the services provided by NU-Link are less sensitive to flows across the interconnector, whereas the constraint cost impact is highly dependent on the scale and direction of flows across the project.

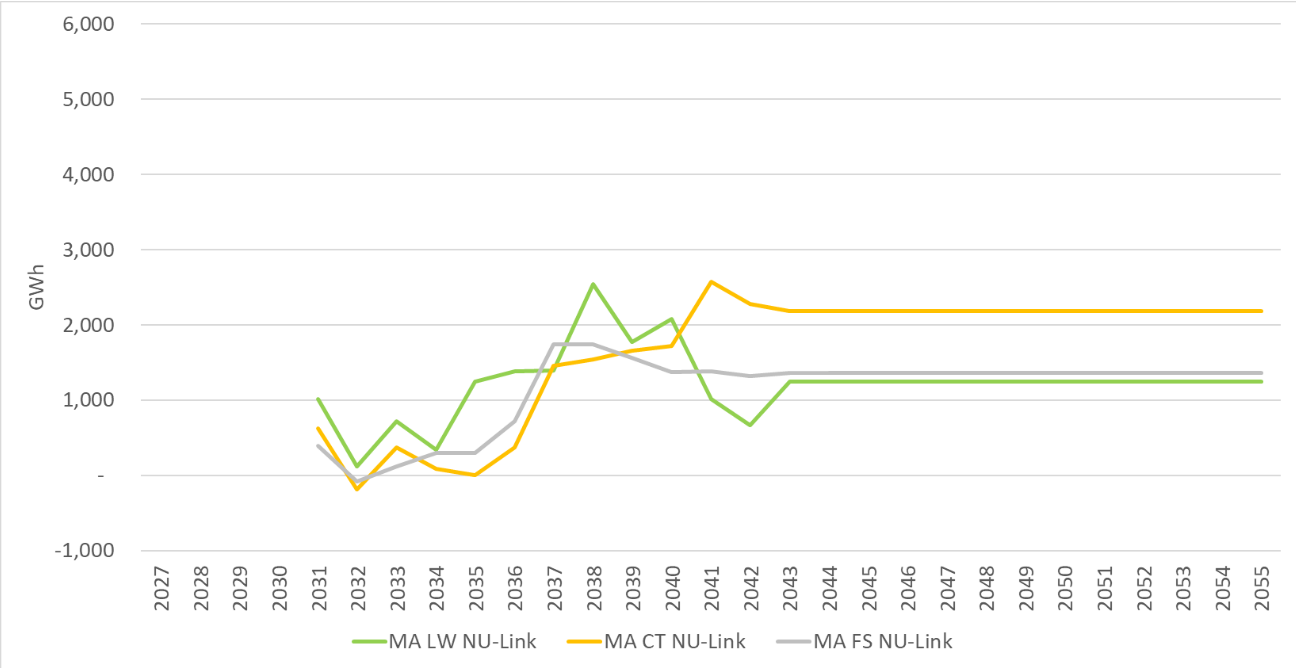
RES curtailment avoided

Figure 251: Annual RES curtailment avoided for NU-Link for the First Additional case.



The above figure shows the renewable energy supply (RES) curtailment avoided on an annual basis for Leading the Way, Consumer Transformation and Falling Short for the First Additional case. Note that beyond 2042, the results are an average of the years 2040, 2041 and 2042, as our detailed modelling with FES22 only extends out to 2042. The figure shows that the level of annual RES curtailment avoided when NU-Link is included is approximately between 0.5TWh and 5TWh, which equates to approximately between 1.4GWh and 13.7GWh per day.

Figure 252: Annual RES curtailment avoided for NU-Link for the Marginal Additional case.



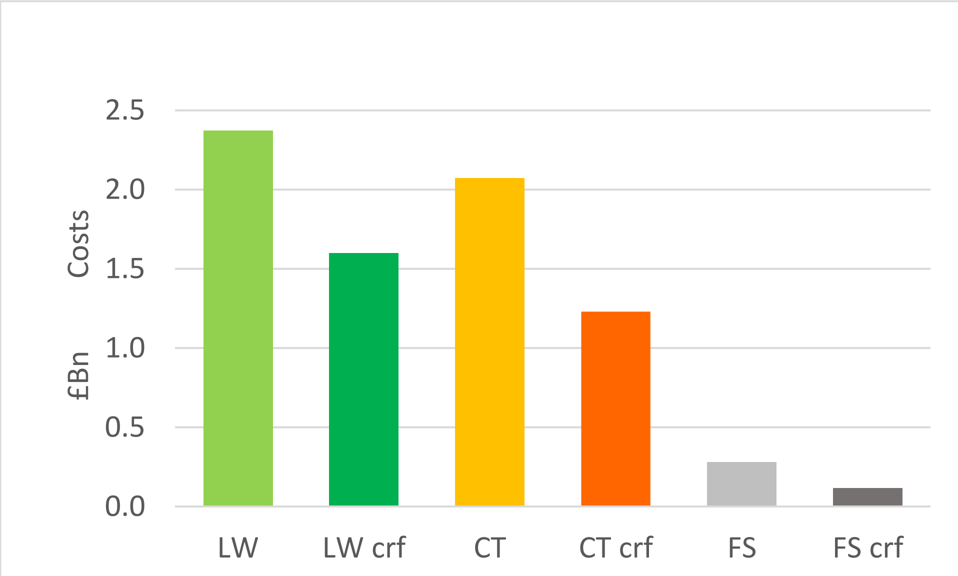
The above figure shows the renewable energy supply (RES) curtailment avoided on an annual basis for Leading the Way, Consumer Transformation and Falling Short for the Marginal Additional case. Note that beyond 2042, the results are an average of the years 2040, 2041 and 2042, as our detailed modelling with FES22 only extends out to 2042. The figure shows that the level of annual RES curtailment avoided when NU-Link is included rises to approximately between 0TWh and 2TWh, which equates to approximately between 0GWh and 5.5GWh per day.

18. Tarchon

Tarchon is a W3 interconnector project. It has a capacity of 1.4GW and connects to Germany.

PV constraint costs

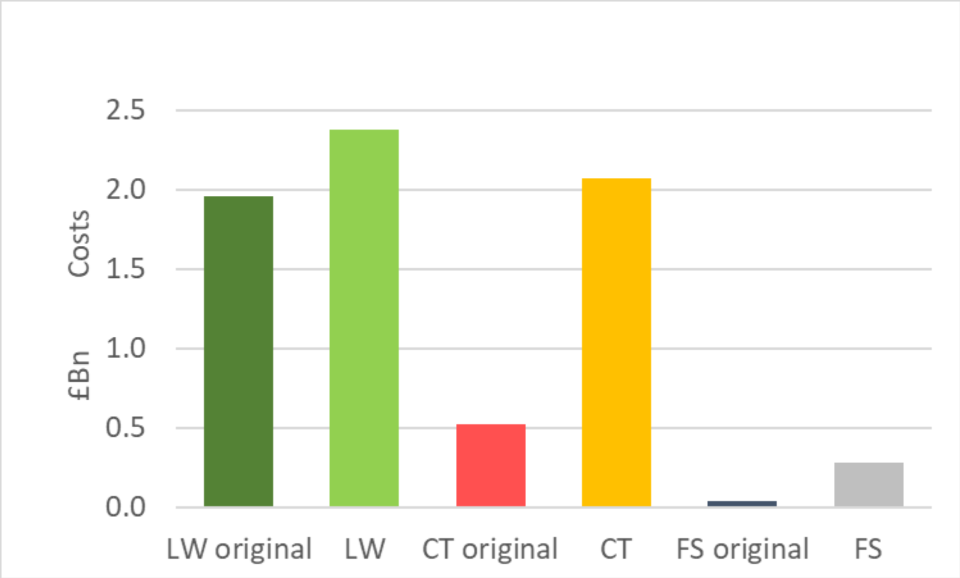
Figure 253: PV additional constraint costs due to Tarchon for the First Additional case, Present Value 25-year, real 2022, £m, without and with Constraint Reduction Factor applied.



The above figure shows the additional constraint costs with the inclusion of Tarchon for the FA case. Without the Constraint Reduction Factor applied, in the Leading the Way scenario (LW) constraint costs are increased by £2.4bn, in Consumer Transformation (CT) by £2.1bn and in the Falling Short (FS) scenario by £0.28bn.

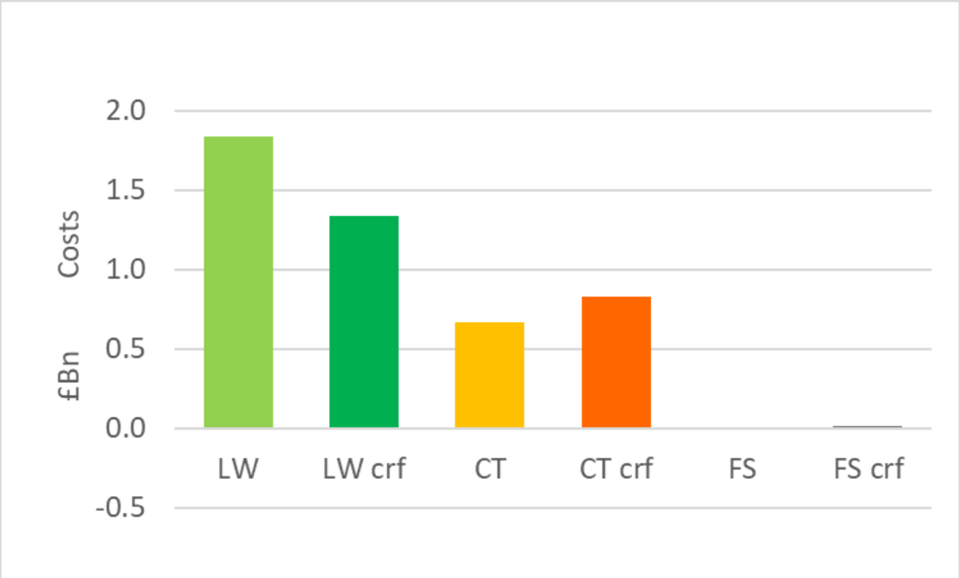
With the Constraint Reduction Factor applied, in the Leading the Way scenario (LW) constraint costs are increased by £1.6bn, in Consumer Transformation (CT) by £1.2bn and in the Falling Short (FS) scenario by £0.12bn.

Figure 254: PV additional constraint costs due to Tarchon for the First Additional case, Present Value 25-year, real 2022, £m, for the original analysis (March 2024) and for Nautilus at Grain with 1.4GW link and Irish demand and generation from TYNDP.



The above figure shows that the changes made to the scenarios, that is the reduction in the capacity of the link connecting the Nautilus offshore platform to Belgium from 3.5GW to 1.4GW and the change in Irish demand and generation to reflect final TYNDP data results in an increase in constraint costs in all three scenarios, with a significantly large increase for CT.

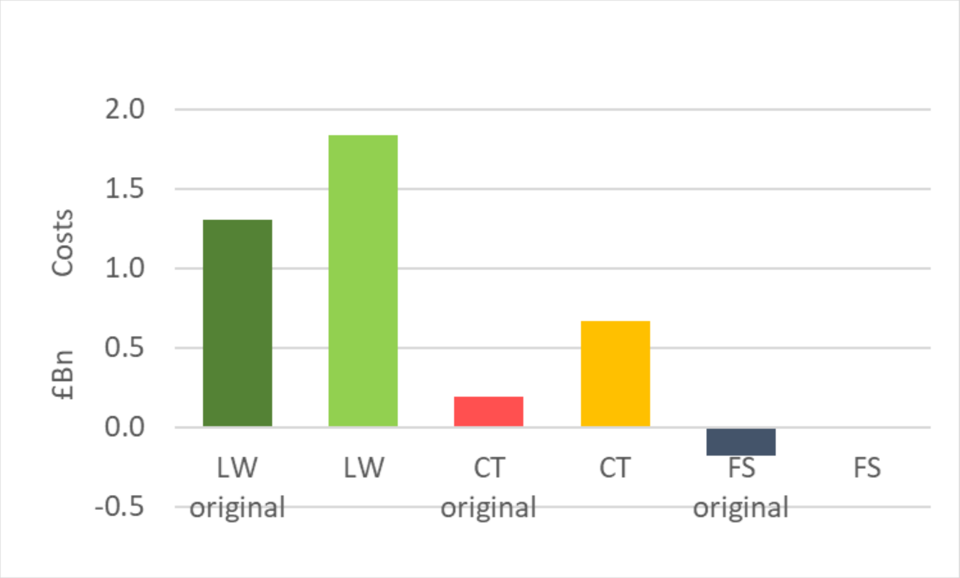
Figure 255: PV additional constraint costs due to Tarchon for the Marginal Additional case, Present Value 25-year, real 2022, £m, without and with Constraint Reduction Factor applied.



The above figure shows the additional constraint costs with the inclusion of Tarchon for the MA case. Without the Constraint Reduction Factor applied, in the Leading the Way scenario (LW) constraint costs are increased by £1.8bn, in Consumer Transformation (CT) by £0.67bn and in the Falling Short (FS) scenario constraint costs are reduced by £0.015bn.

With the Constraint Reduction Factor applied, in the Leading the Way scenario (LW) constraint costs are increased by £1.3bn, in Consumer Transformation (CT) by £0.83bn and in the Falling Short (FS) scenario by £0.01bn.

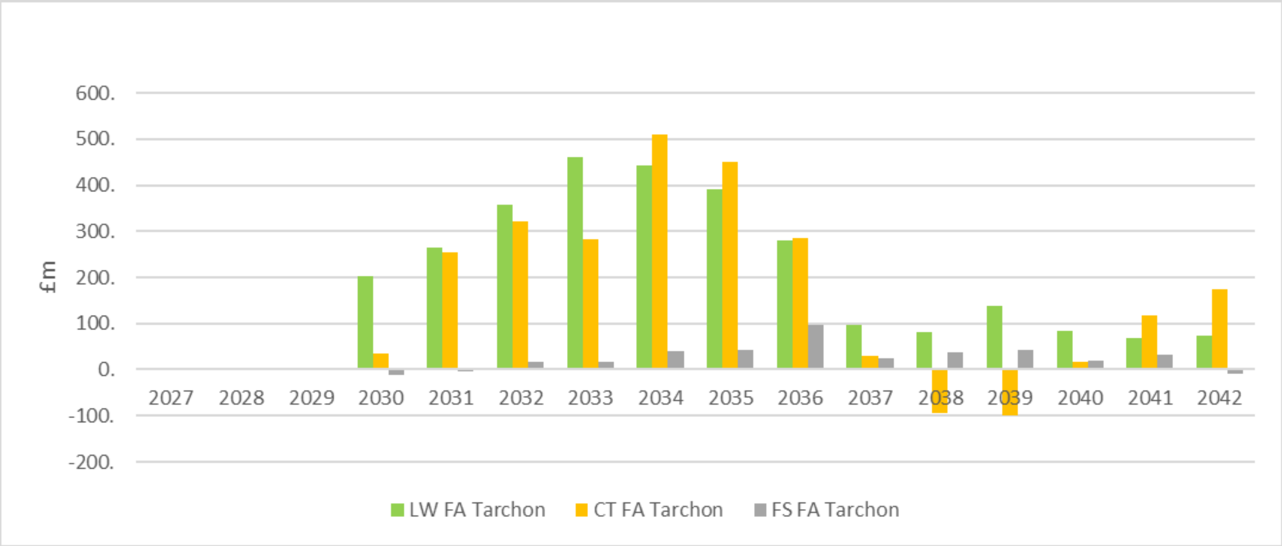
Figure 256: PV additional constraint costs due to Tarchon for the Marginal Additional case, Present Value 25-year, real 2022, £m, for the original analysis (March 2024) and for Nautilus at Grain with 1.4GW link and Irish demand and generation from TYNDP.



The above figure shows that the changes made to the scenarios, that is the reduction in the capacity of the link connecting the Nautilus offshore platform to Belgium from 3.5GW to 1.4GW and the change in Irish demand and generation to reflect final TYNDP data results in an increase in constraint costs in all three scenarios.

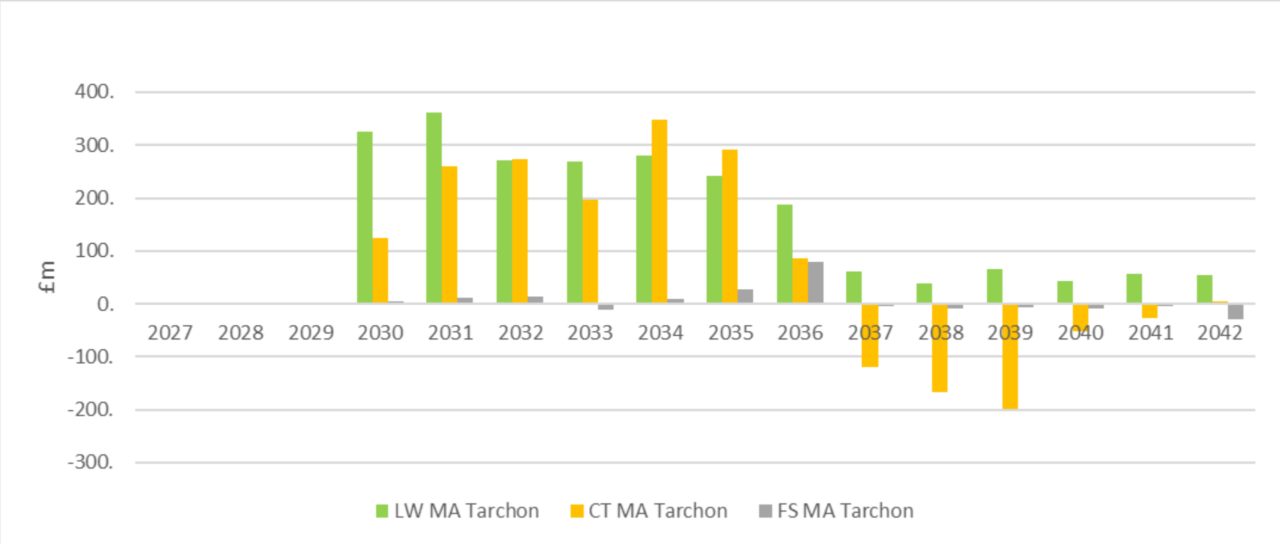
Annual constraint costs (undiscounted)

Figure 257: Additional annual constraint costs (undiscounted) due to Tarchon for the First Additional case.



The above figure shows that Tarchon results in an increase in constraint costs of approximately £200m to £500m (undiscounted) in CT and LW for the years 2031 to 2036. In FS constraint cost increases are very much lower, with small savings in 2030, 2031 and 2042. CT also shows savings in 2038 and 2039. The results are higher than the original (March 2024) results, particularly for CT.

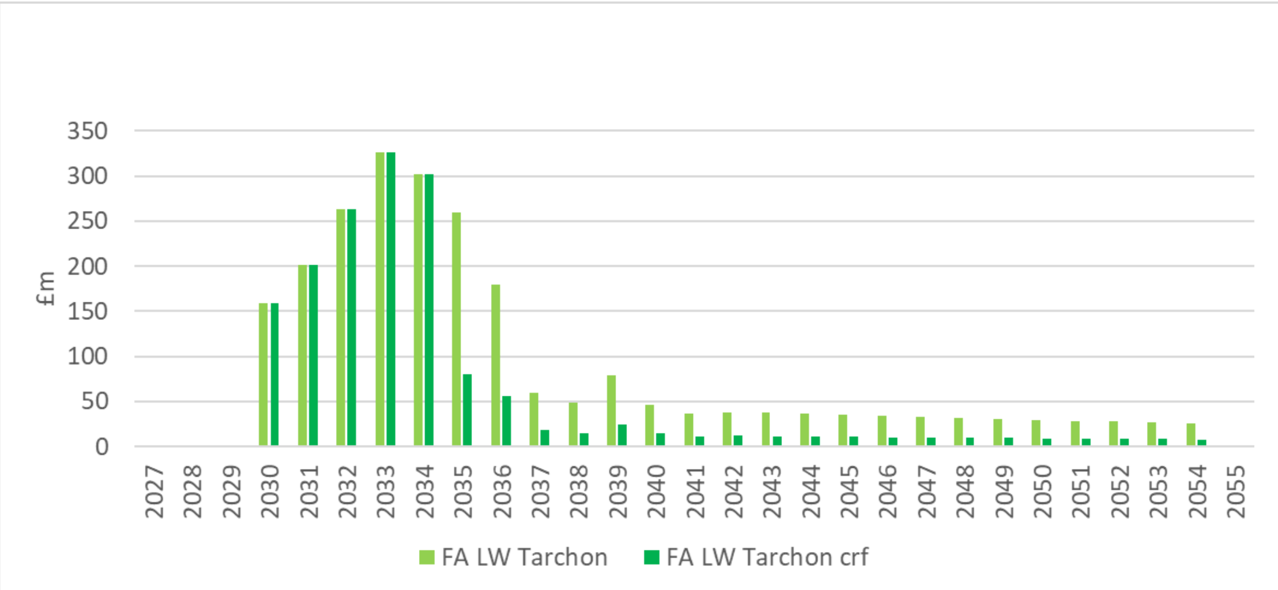
Figure 258: Additional annual constraint costs (undiscounted) due to Tarchon for the Marginal Additional case.



In the Marginal Additional case, Tarchon results in an increase in constraint costs of approximately £200m to £300m (undiscounted) in CT and LW for the years 2032 to 2035. CT shows significant constraint saving for the years 2037 to 2039 and smaller saving in 2040 and 2041. FS shows constraint savings for the years 2037 to 2042, and for the other years shows considerably lower levels of additional constraint costs compared to LW and CT. The results are significantly higher than the original (March 2024) results.

Annual constraint costs (discounted), without and with Constraint Reduction Factor

Figure 259: Additional annual constraint costs (discounted) due to Tarchon for the First Additional case for Leading the Way, without and with Constraint Reduction Factor applied.



The above chart shows the additional constraint costs without and with the Constraint Reduction Factor (CRF) applied for the Leading the Way scenario for the First Additional case. The chart shows the impact of the CRF being applied from 2035 onwards.

Figure 260: Additional annual constraint costs (discounted) due to Tarchon for the First Additional case for Consumer Transformation, without and with Constraint Reduction Factor applied.

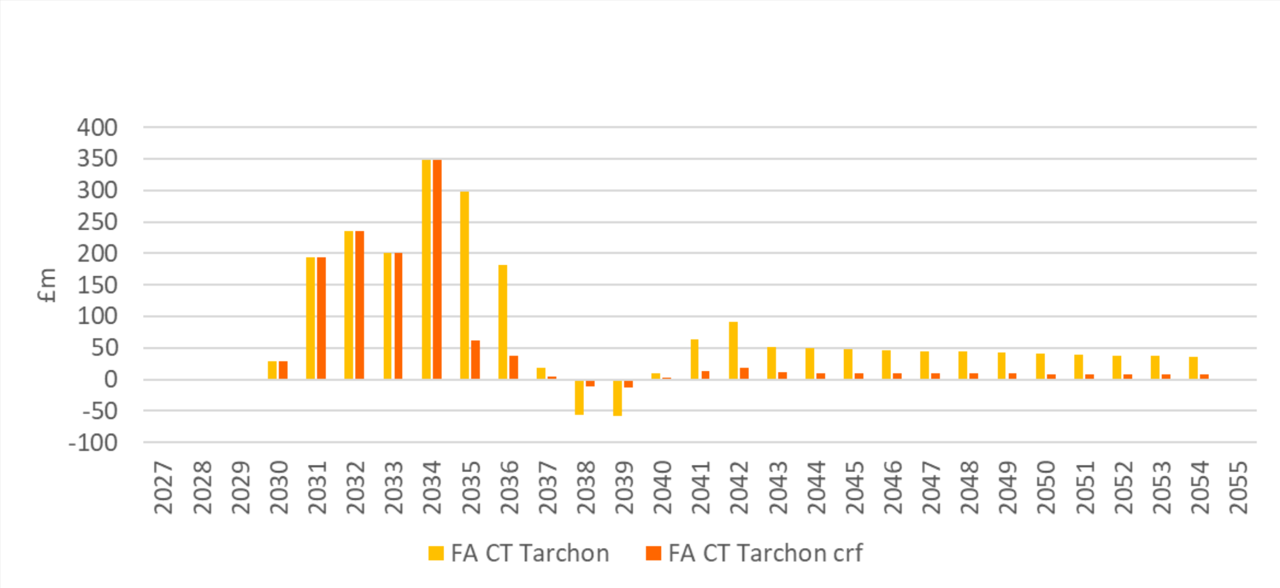
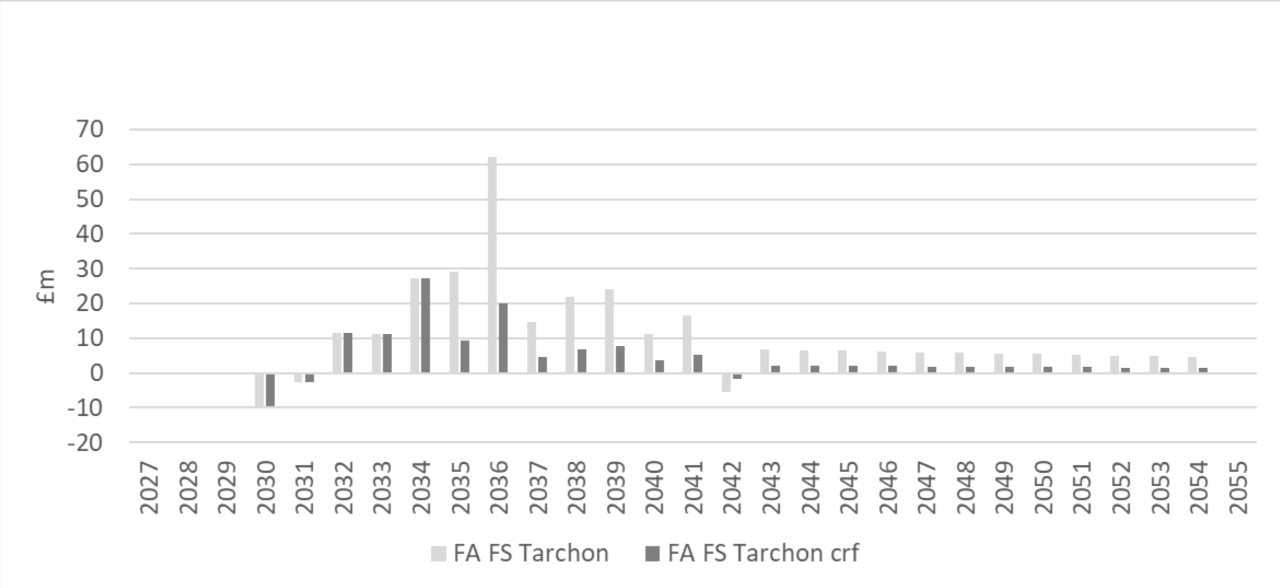
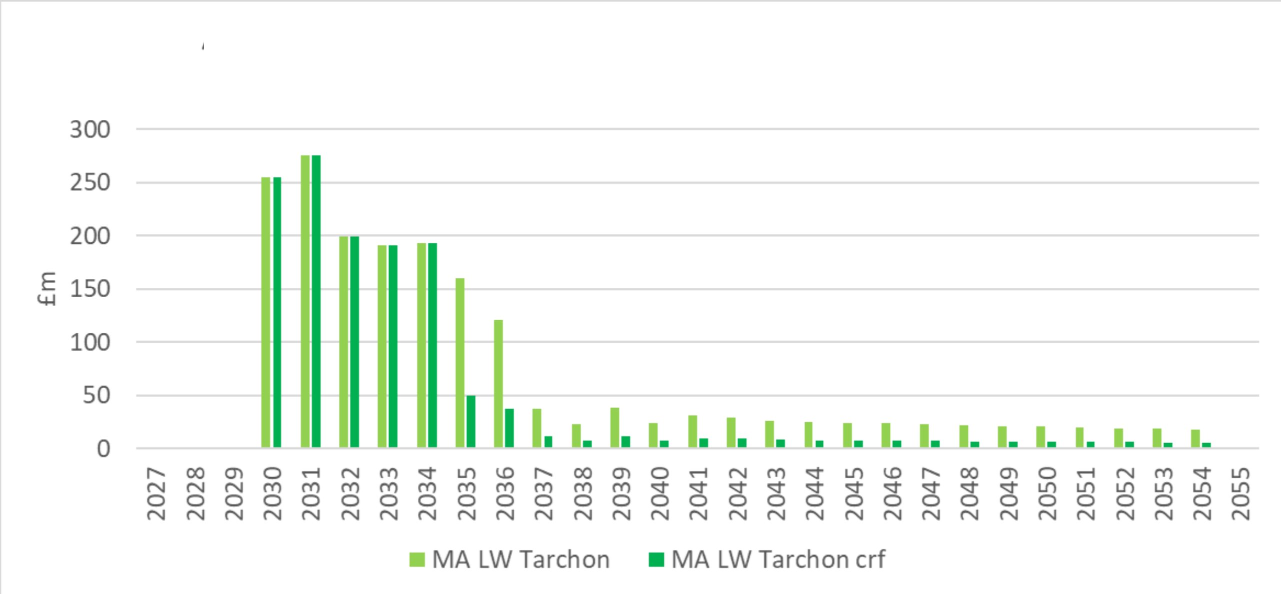


Figure 261: Additional annual constraint costs (discounted) due to Tarchon for the First Additional case for Falling Short, without and with Constraint Reduction Factor applied.



The above chart shows the additional constraint costs without and with the Constraint Reduction Factor (CRF) applied. The chart shows the impact of the CRF being applied from 2035 onwards.

Figure 262: Additional annual constraint costs (discounted) due to Tarchon for the Marginal Additional case for Leading the Way, without and with Constraint Reduction Factor applied.



The above chart shows the additional constraint costs without and with the Constraint Reduction Factor (CRF) applied for the Leading the Way scenario for the Marginal Additional case. The chart shows the impact of the CRF being applied from 2035 onwards.

Figure 263: Additional annual constraint costs (discounted) due to Tarchon for the Marginal Additional case for Consumer Transformation, without and with Constraint Reduction Factor applied.

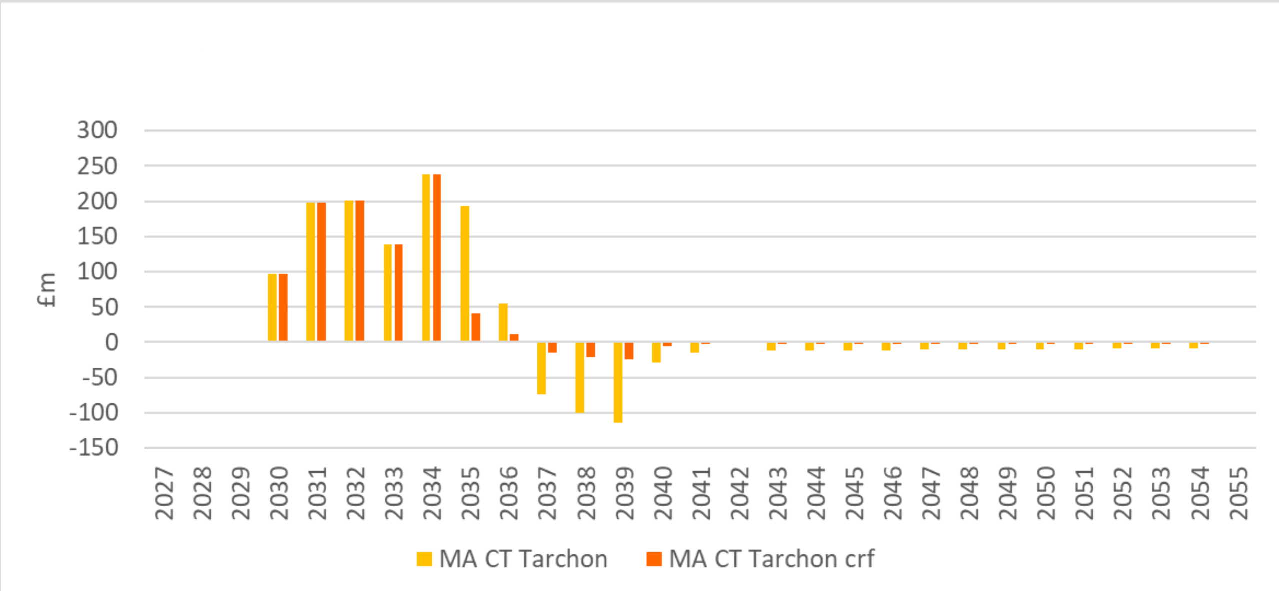
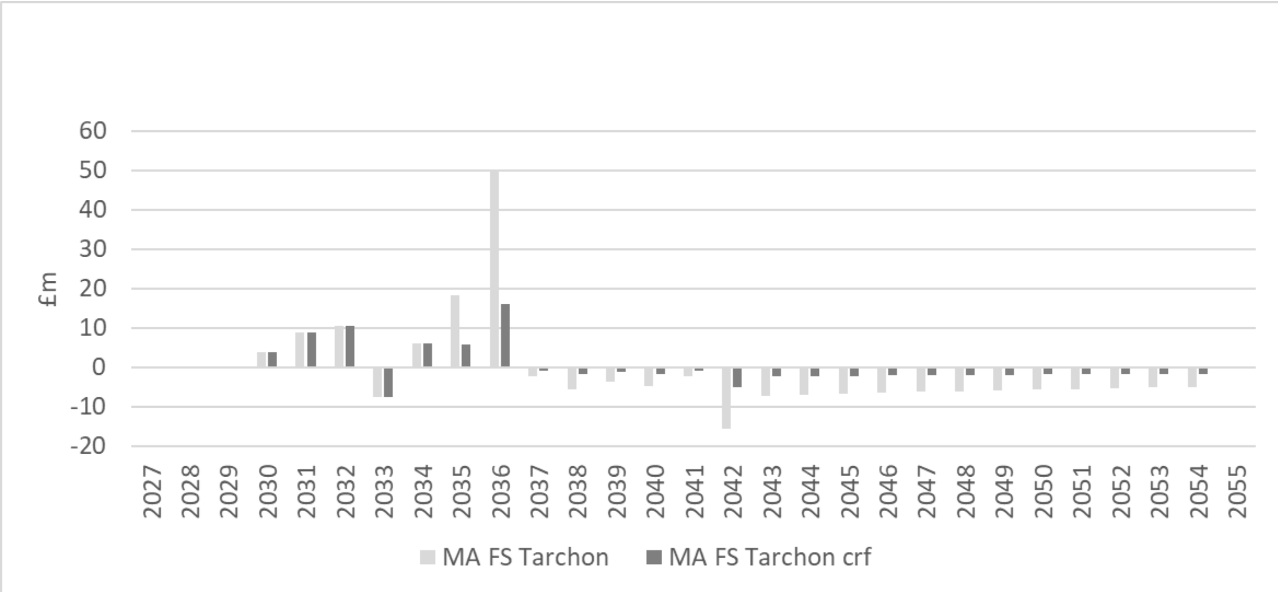


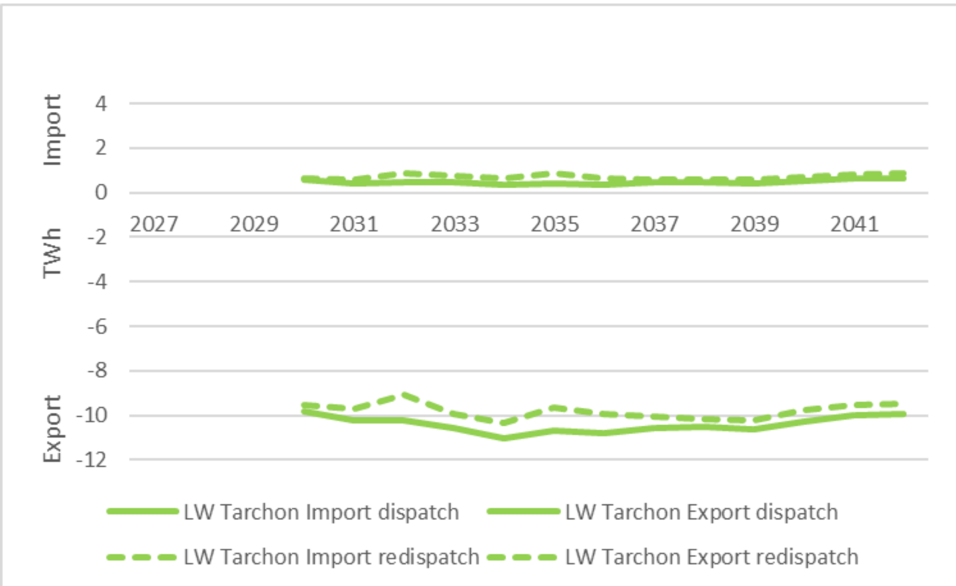
Figure 264: Additional annual constraint costs (discounted) due to Tarchon for the Marginal Additional case for Falling Short, without and with Constraint Reduction Factor applied.



The above figure shows that as the average of the annual constraint costs for the years 2040, 2041 and 2042 results in a negative number, that is a saving, the CRF results in a reduction in constraint savings rather than a reduction in constraint costs.

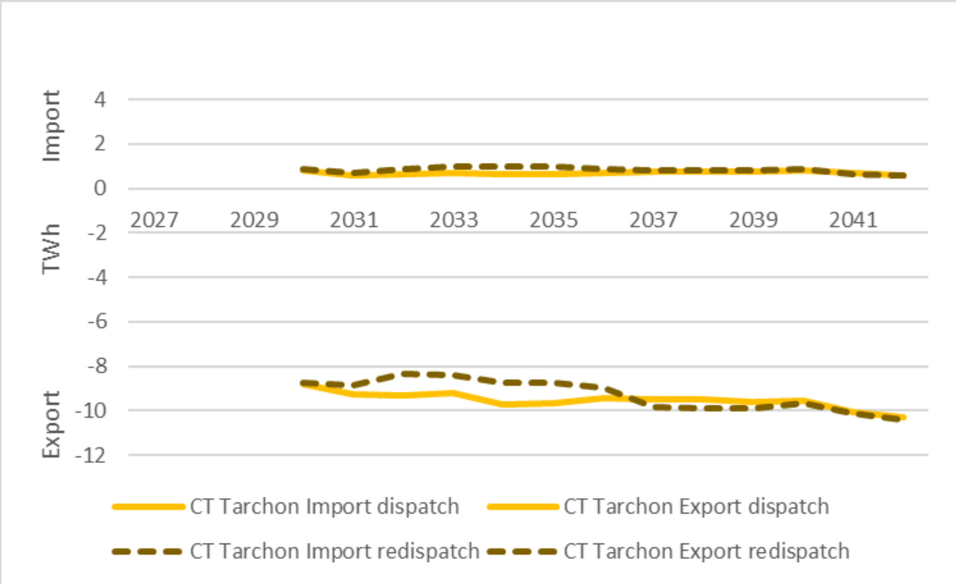
Annual import and export flows for dispatch and redispatch

Figure 265: Annual import and export flows for Tarchon in the FA case for Leading the Way.



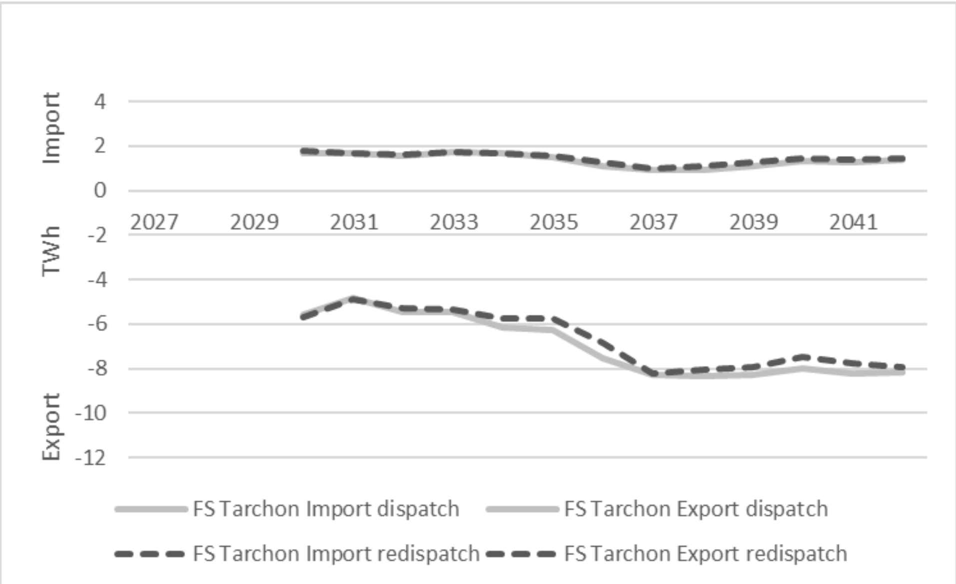
The above figure shows high exports and very low imports in the dispatch. The redispatch shows a small reduction in exports and a very small increase in imports. Compared to the original (March 2024) results, exports and imports are very similar.

Figure 266: Annual import and export flows for Tarchon in the FA case for Consumer Transformation.



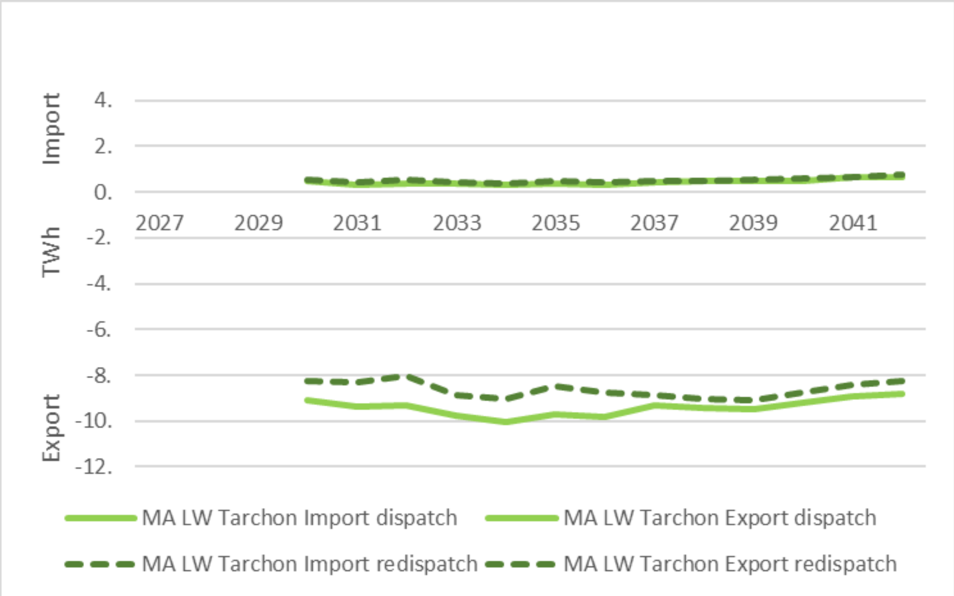
The above figure shows high exports and low imports in the dispatch. The redispatch shows a small reduction in exports and a very small increase in imports. Compared to the original (March 2024) results, exports and imports are very similar.

Figure 267: Annual import and export flows for Tarchon in the FA case for Falling Short.



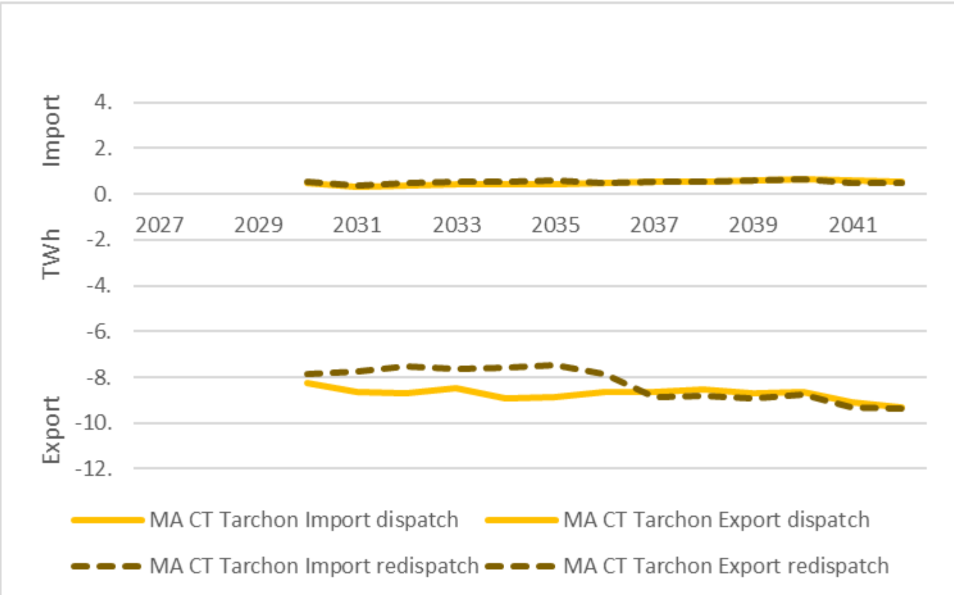
The above figure shows that for the First Additional case Tarchon has increasing levels of exports over the forecast period up to 2037 for Falling Short. The redispatch shows very little change in imports or exports. Compared to the original (March 2024) results, exports and imports are very similar.

Figure 268: Annual import and export flows for Tarchon in the MA case for Leading the Way.



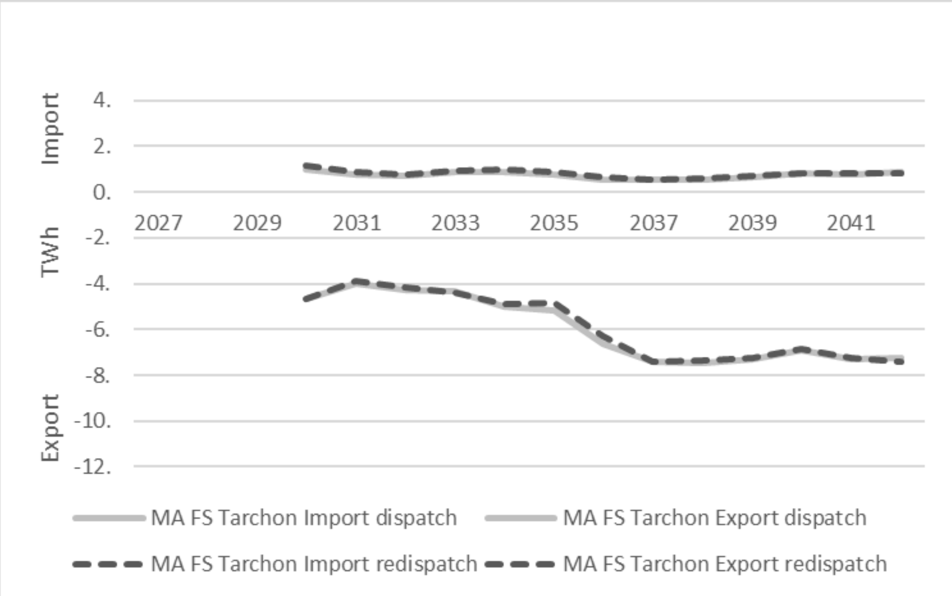
The above figure shows for the dispatch high exports and low imports. The redispatch shows some reduction in exports, especially I the earlier years and no change in imports. Compared to the original (March 2024) results, exports and imports are very similar.

Figure 269: Annual import and export flows for Tarchon in the MA case for Consumer Transformation.



The above figure shows high exports and low imports in the dispatch. The redispatch shows some reduction in exports between 2030 and 2036 and virtually no change in imports. Compared to the original (March 2024) results, exports and imports are very similar.

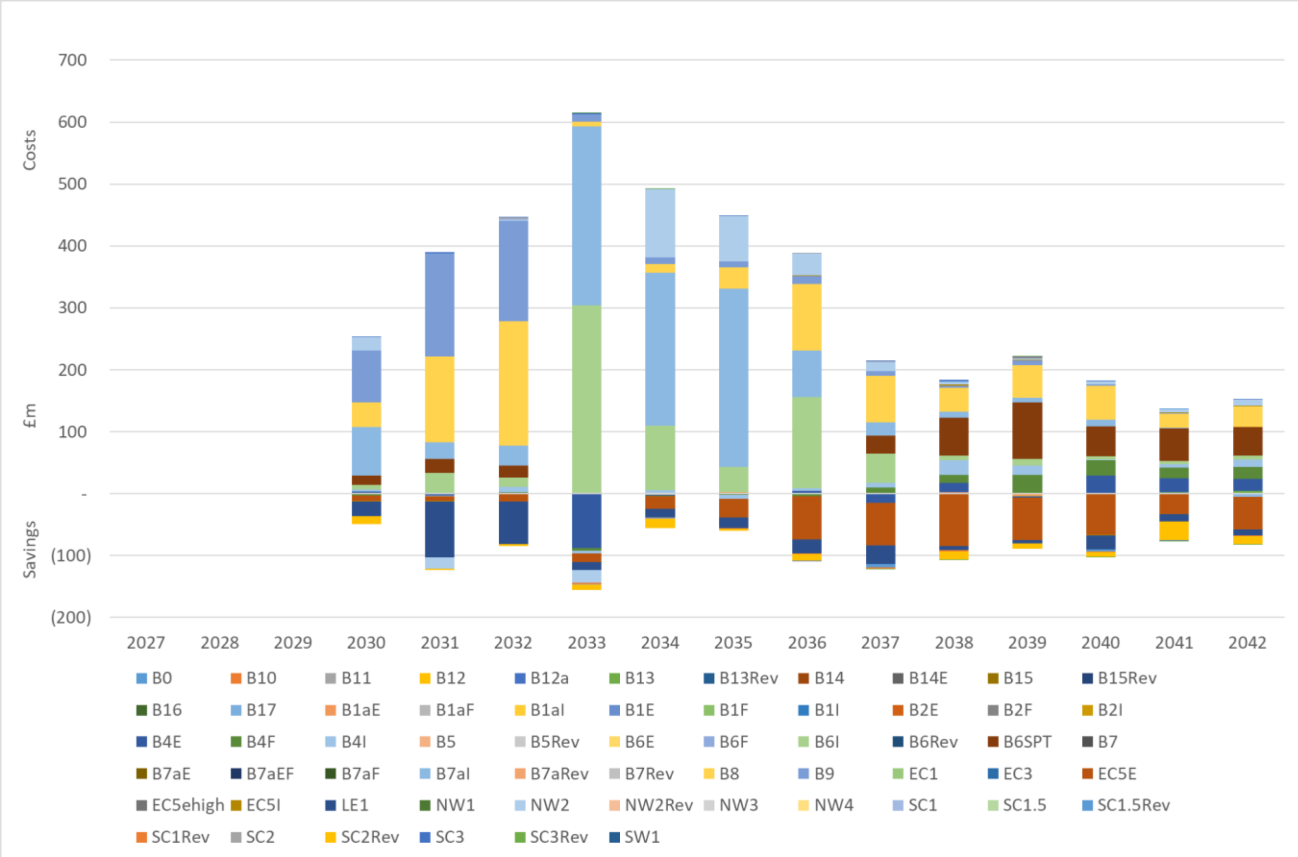
Figure 270: Annual import and export flows for Tarchon in the MA case for Falling Short.



The above figure shows that for the Marginal Additional case, Tarchon has increasing exports and low imports in the dispatch. The redispatch shows very little change in flows for exports or imports. Compared to the original (March 2024) results, exports and imports are very similar.

Change in constraint costs by boundary

Figure 271: Change in constraint costs by boundary for Tarchon for the First Additional case for Leading the Way.



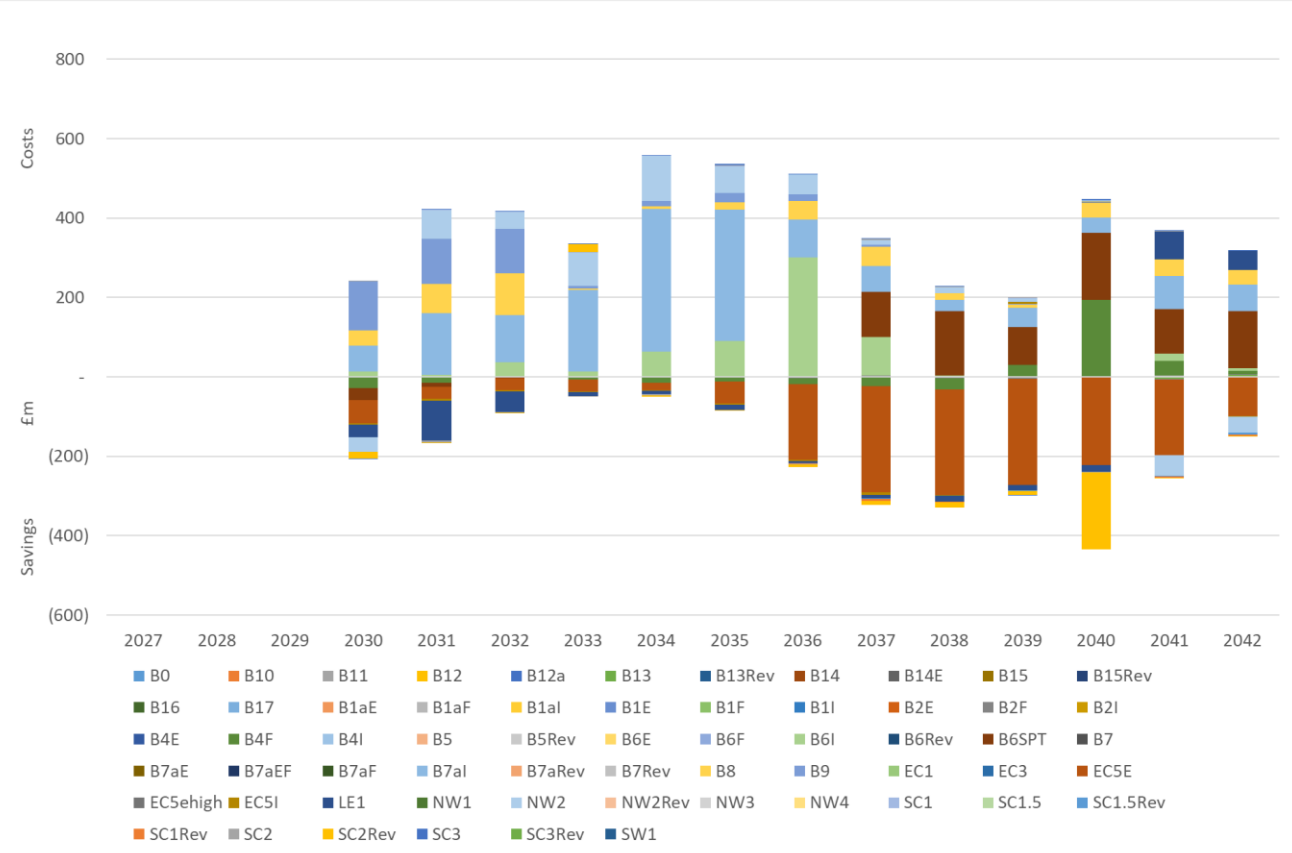
The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for Tarchon for the First Additional case for the Leading the Way scenario. Each different colour represents the change in constraint costs for a particular boundary. It is important to note that the chart shows changes in constraint costs by boundary, i.e. the difference between constraint costs when the project is included and when the project is excluded.

The figure shows that Tarchon increases constraint costs on certain boundaries but also reduces constraint costs on others. Whether the impact is an increase in constraint costs or a reduction in constraint costs for a particular boundary, changes from year to year. The size of change in constraint costs by boundary can also vary significantly from year to year. This is shown clearly in the years 2033 to 2034. The figure also shows that the specific boundaries that have the greatest impact on the total change in constraint costs can vary from year to year. These factors are a result of the changes in demand, supply and network capability over time.

In general, Tarchon increases constraint costs on several northern and midland boundaries but relieves congestion on various southern boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis, constraint costs are higher on several northern boundaries and one Welsh boundary.

Figure 272: Change in constraint costs by boundary for Tarchon for the First Additional case for Consumer Transformation.

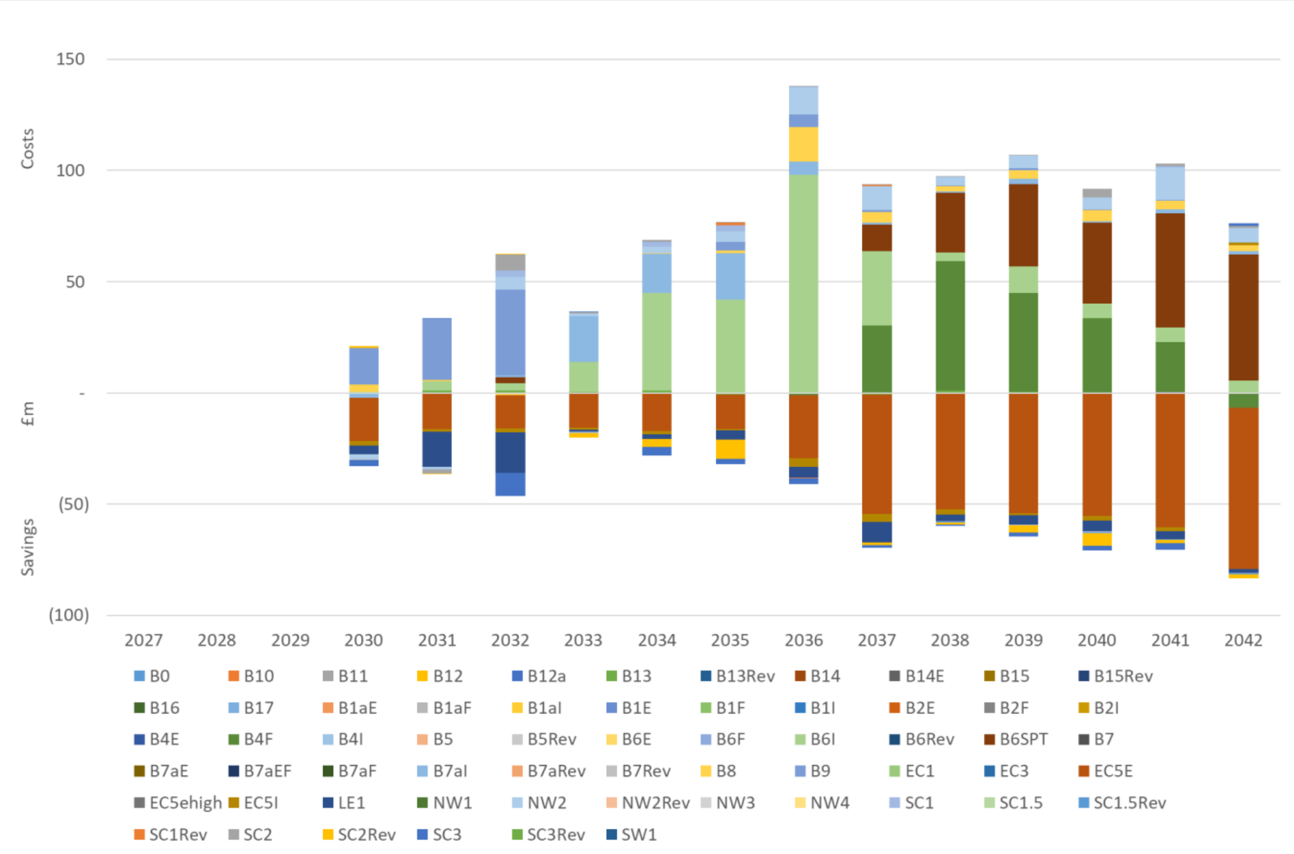


The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for Tarchon for the First Additional case for the Consumer Transformation scenario.

In general, Tarchon increases constraint costs on several northern and midland boundaries but relieves congestion on various southern boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis, constraint costs are significantly higher on several northern boundaries and one Welsh boundary.

Figure 273: Change in constraint costs by boundary for Tarchon for the First Additional case for Falling Short.

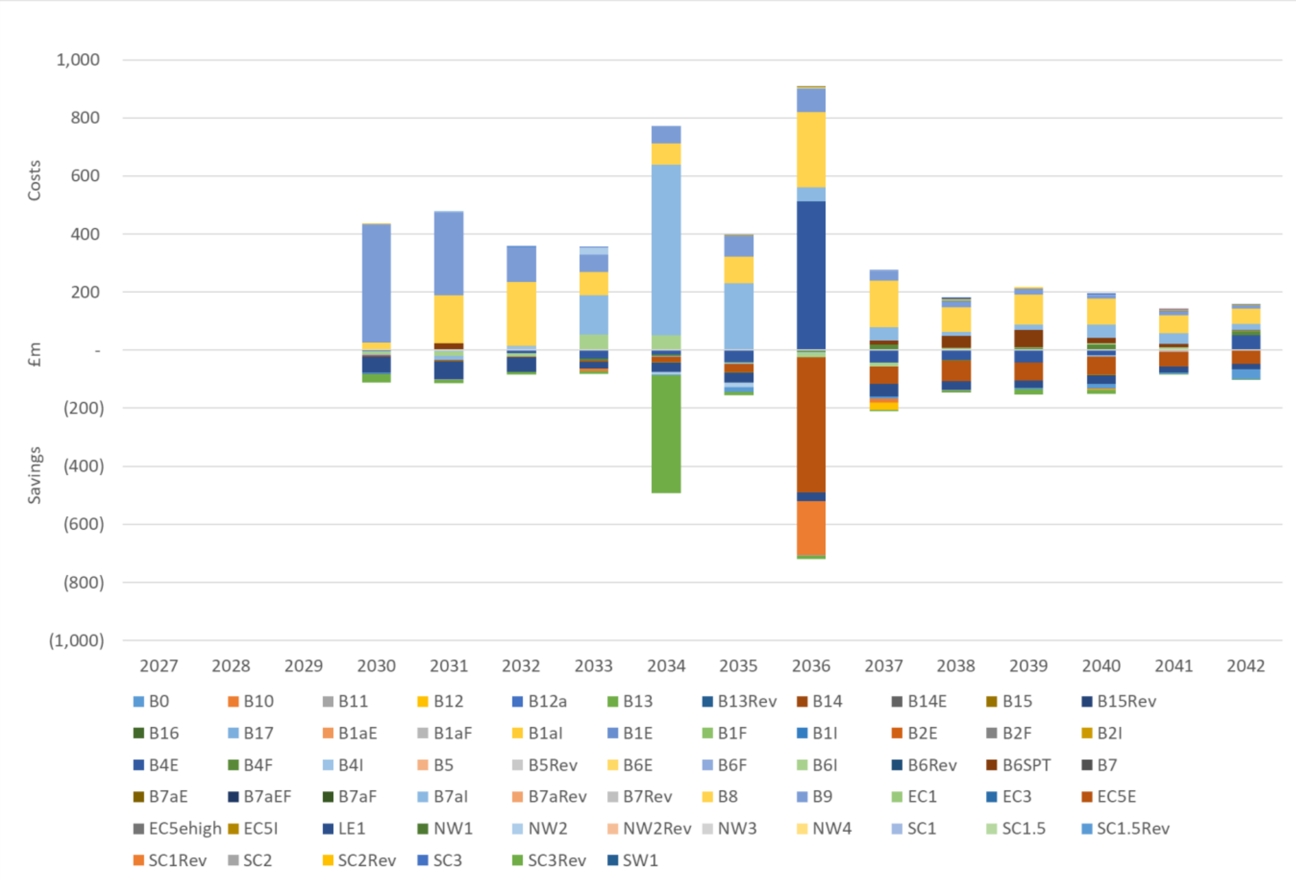


The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for Tarchon for the First Additional case for the Falling Short scenario.

In general, Tarchon increases constraint costs on several northern and midland boundaries but relieves congestion on various southern boundaries. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis, constraint costs are significantly higher on several northern boundaries and one Welsh boundary.

Figure 274: Change in constraint costs by boundary for Tarchon for the Marginal Additional case for Leading the Way.



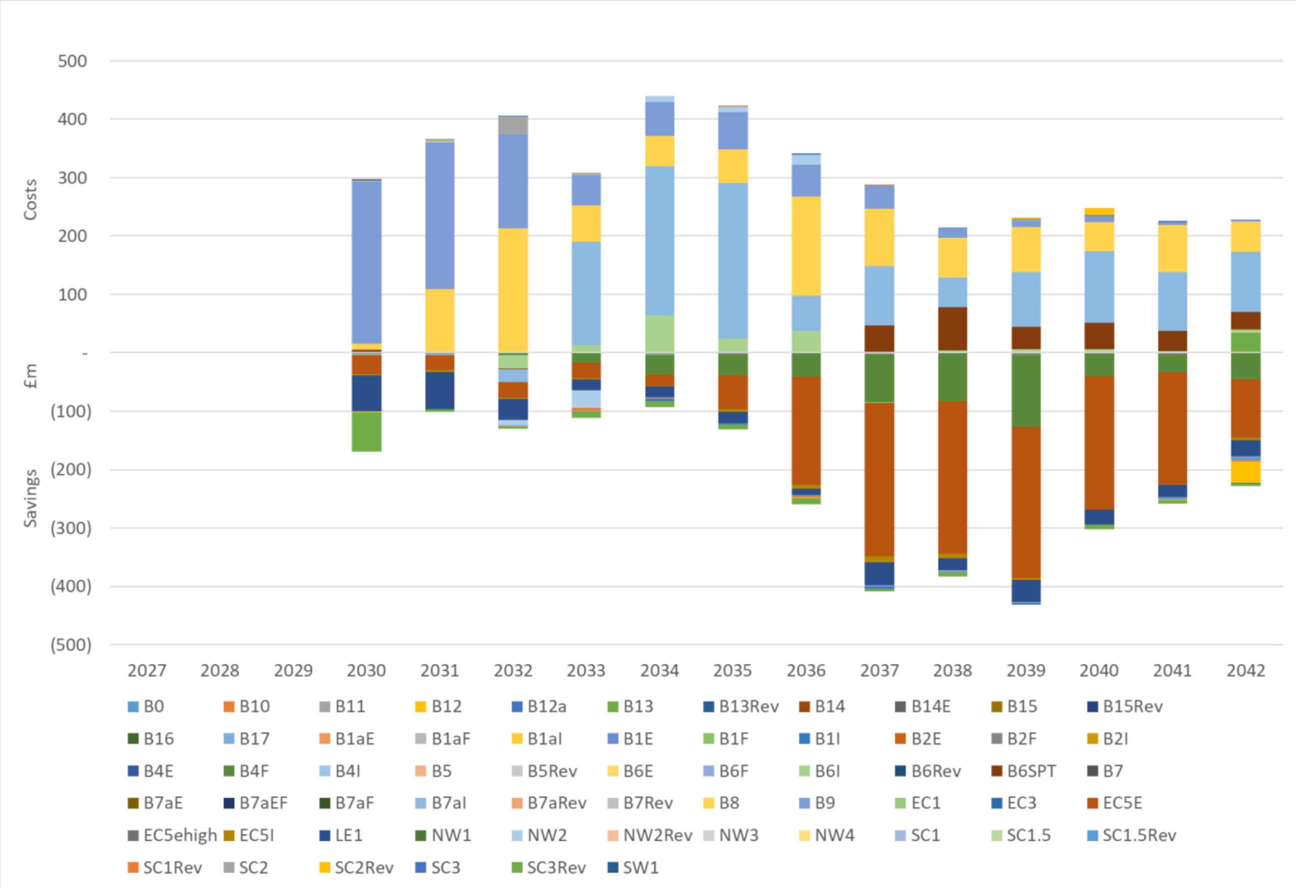
The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for Tarchon for the Marginal Additional case for the Leading the Way scenario.

In general, Tarchon increases constraint costs on several northern and midland boundaries but relieves congestion on certain southern boundaries and one eastern boundary. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Tarchon relieves significant congestion on several southern and one eastern boundary in 2034 and 2036. The saving only occurs for a single year suggesting the combination of supply, demand and boundary capabilities that enable such a significant saving across one boundary when Tarchon is included only exist for that year. That is in later years, supply and demand patterns and boundary capabilities will have evolved such that the model is no longer able to produce the lowest total cost solution by significantly reducing constraint costs across that particular boundary when Tarchon is included.

Compared to the original (March 2024) analysis, constraint costs are higher on several northern and midland boundaries and lower on one eastern boundary.

Figure 275: Change in constraint costs by boundary for Tarchon for the Marginal Additional case for Consumer Transformation.

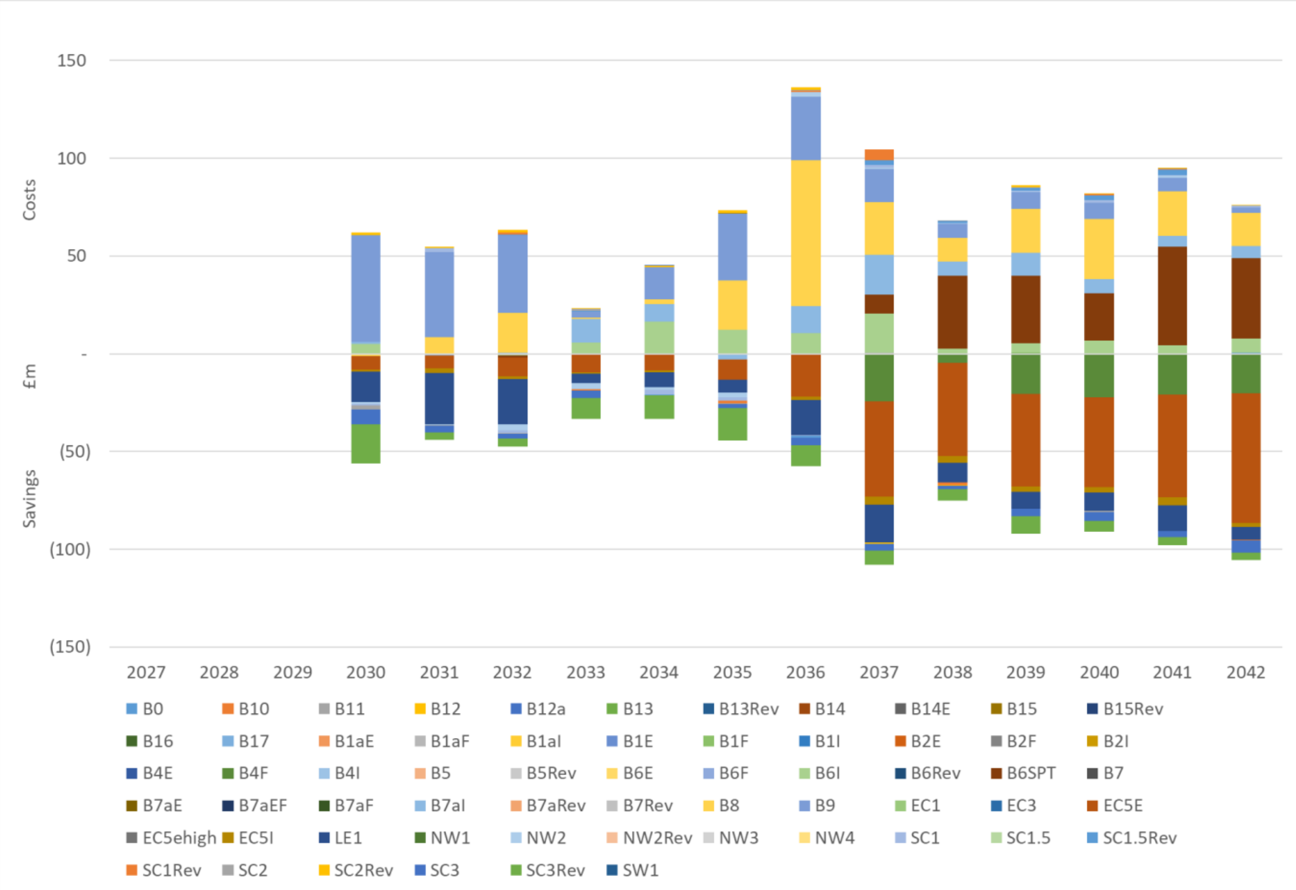


The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for Tarchon for the Marginal Additional case for the Consumer Transformation scenario.

In general, Tarchon increases constraint costs on several northern and midland boundaries but relieves congestion on various boundaries and one eastern boundary. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis, constraint costs are higher on several northern and midland boundaries.

Figure 276: Change in constraint costs by boundary for Tarchon for the First Additional case for Falling Short.



The above figure shows the annual change in constraint costs (undiscounted), broken down by boundary for Tarchon for the Marginal Additional case for the Falling Short scenario.

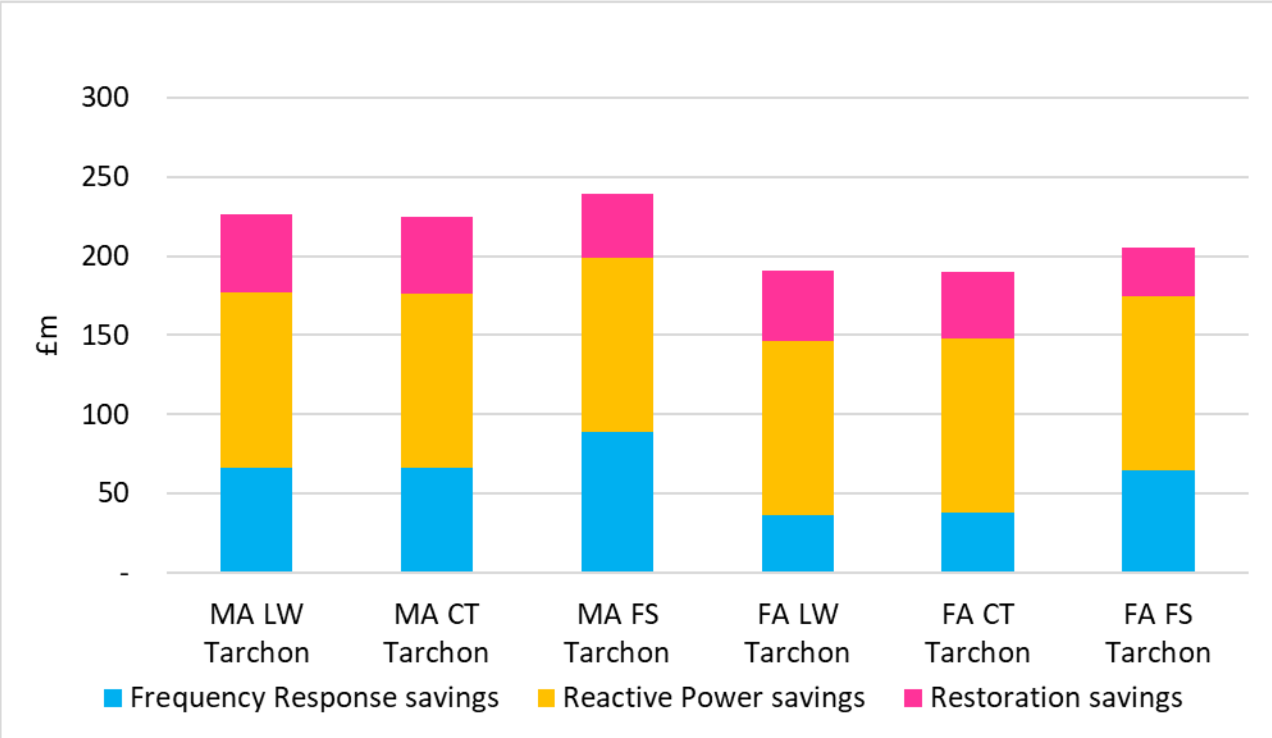
In general, Tarchon increases constraint costs on several northern and midland boundaries but relieves congestion on various southern boundaries and one eastern boundary. The impact of the project may not necessarily be on boundaries that are geographically close to the project. This is to be expected, as the model is minimising total constraint costs by taking balancing actions across the whole GB network and observing network capabilities, i.e. boundary capacities.

Compared to the original (March 2024) analysis, constraint costs are slightly higher on several northern and midland boundaries.

PV system operation

Note: The modelling and analysis for system operation is the same as that within the March 2024 report. It was not necessary to repeat the work because the change in modelling assumptions would not produce a material change in the results.

Figure 277: PV potential system operability savings for Tarchon, Present Value 25-year, real 2022, £m.

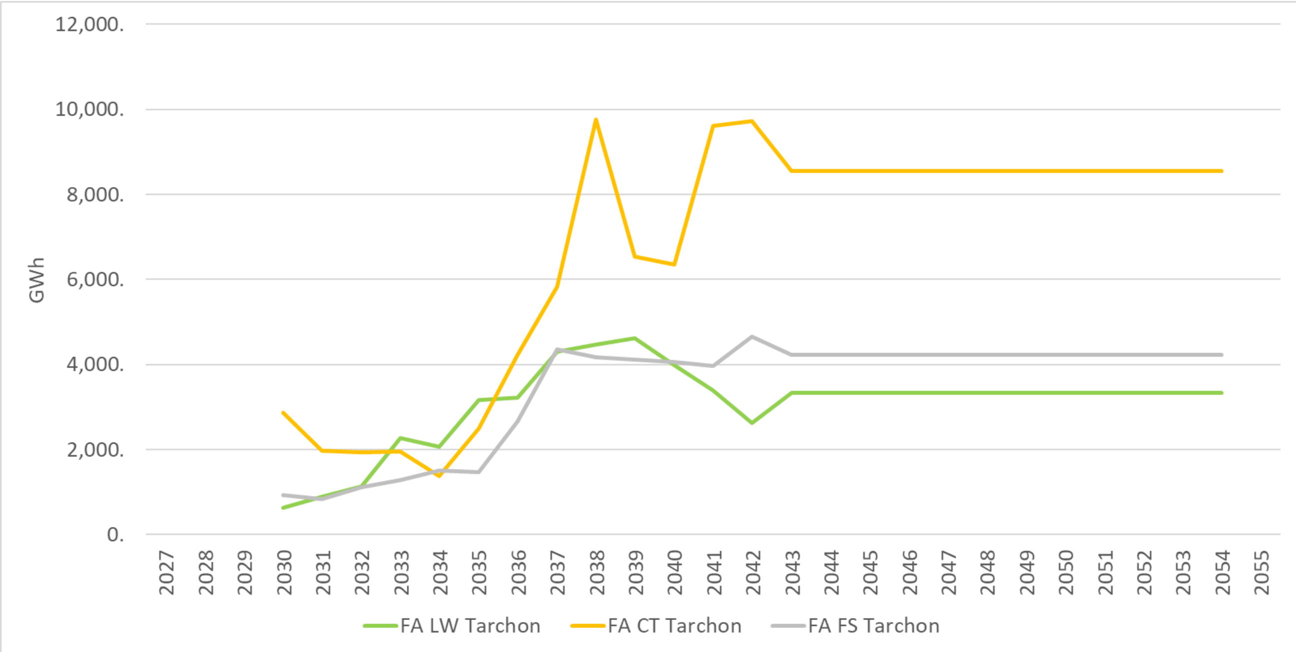


The above figure shows the potential savings for frequency response, reactive power and restoration services in present value (25-year, 2022 £m) for Tarchon for Leading the Way, Consumer Transformation and Falling Short for both the Marginal Additional and First Additional cases. There is considerable uncertainty around forecasting potential system operability benefits over a 25-year time horizon, but the figure shows that there is potentially significant savings in frequency response, reactive power and restoration services.

There is little variation across the three scenarios and also across the First Additional and Marginal Additional cases. This is because the potential system operability savings from the services provided by Tarchon are less sensitive to flows across the interconnector, whereas the constraint cost impact is highly dependent on the scale and direction of flows across the project.

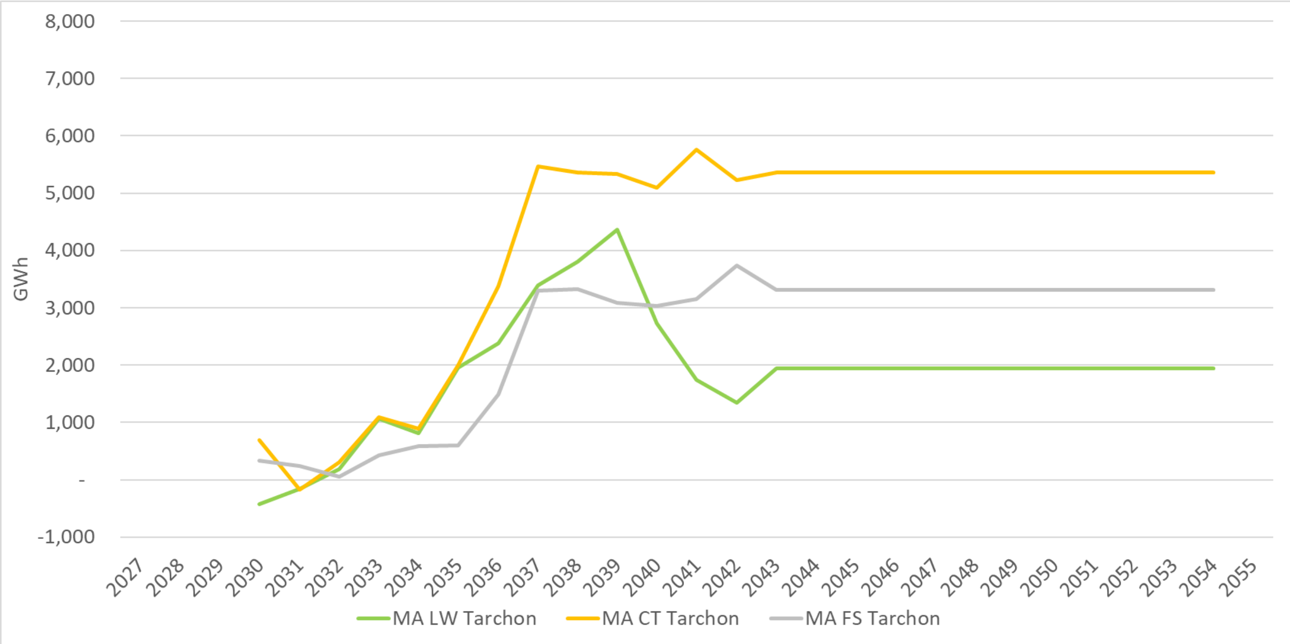
RES curtailment avoided

Figure 278: Annual RES curtailment avoided for Tarchon for the First Additional case.



The above figure shows the renewable energy supply (RES) curtailment avoided on an annual basis for Leading the Way, Consumer Transformation and Falling Short for the First Additional case. Note that beyond 2042, the results are an average of the years 2040, 2041 and 2042, as our detailed modelling with FES22 only extends out to 2042. The figure shows that the level of annual RES curtailment avoided when Tarchon is included is approximately between 1TWh and 9TWh, which equates to approximately between 2.7GWh and 24.7GWh per day. The figure shows that the final three years modelled in BID3 (2040 to 2042), which are used to extrapolate later years, are particularly high for the CT scenario.

Figure 279: Annual RES curtailment avoided for Tarchon for the Marginal Additional case.



The above figure shows the renewable energy supply (RES) curtailment avoided on an annual basis for Leading the Way, Consumer Transformation and Falling Short for the Marginal Additional case. Note that beyond 2042, the results are an average of the years 2040, 2041 and 2042, as our detailed modelling with FES22 only extends out to 2042. The figure shows that the level of annual RES curtailment avoided when Tarchon is included rises to approximately between 2TWh and 5TWh, which equates to approximately between 5.5GWh and 13.7GWh per day.

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