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THE CASE FOR CMP405

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Contents

1 Executive summary

1.1 Key messages from this report

- In the current TNUoS charging methodology the demand charge is “floored at zero”, which means charges do not reflect the impact of sources of demand, in some locations, on relieving network constraints, and hence reducing the need for network investment;
- As a result, storage assets can face a mismatch between a cost reflective generation locational signal reflecting the impact of their generation on increasing constraints, and a distorted demand locational signal that does not reflect their impact from charging on relieving constraints;
- CMP405 would address this defect for storage assets by paying a demand credit to storage linked to the Year Round element of network charges; Implementation now is consistent with government policy to develop policy to enable investment in large scale duration storage by 2024.
- Our modelling shows that storage in export constrained zones tends to charge during periods of constraints, supporting the cost reflectivity of the proposed CMP405 demand credit;
- Improving the cost reflectivity of TNUoS charging signals should lead to more efficient investment decisions, reducing system costs. Our modelling shows that additional storage in export constrained zones leads to sizeable reductions in operational system costs under a range of possible future scenarios;
- In the long term, we would expect a more efficient system to lead to consumer cost benefits, although the shorter term impacts can be more uncertain and dependent on market structure. Our modelling illustrates the potential for consumer cost benefits in both the short term and long term;
- Sound economic principles such as minimising distortions, fairness, and practical considerations should form the basis of the final decision in relation to any changes to network charging arrangements. Based on our assessment, the introduction of a CMP405 demand credit would better align the TNUoS charging framework with these principles and therefore it is appropriate for CMP405 to be taken forwards; and
- An appropriate design of the CMP405 demand credit would not distort dispatch incentives and would reflect in scale the extent to which assets contribute to the relief of constraints i.e. by scaling the credit dependent on an asset’s load factor during periods of constraint (so-called ‘constrained ALF’).

1.2 Background and motivation

Current GB locational transmission network charges (TNUoS) reflect estimates of the “forward looking” network costs triggered by incremental use of the network by generation, demand and storage. The charges aim to send efficient locational signals to generation and demand users by internalising the costs they impose on the network (or the benefits they create).

The charges are intended to reflect the changing nature of the GB electricity generating fleet and the impact that different users have on transmission network investment decisions. Charges are composed of two ‘cost reflective' elements which separately recognise the drivers of network investments that provide for peak demand security (‘Peak Security’ costs) and, network investments that ensure a balance between network investment costs and constraint costs (‘Year Round’ costs).

Demand users face a single charge that combines both Peak Security and Year Round costs, which is payable based on a user’s consumption measured at times of peak demand (so-called “triad” periods). ESO’s transmission charging model currently calculates that in half of all network zones, demand reduces the need for incremental network investment and therefore demand users should receive a transmission charging credit.[1]

However, if demand received such a credit, users in these zones would be paid to increase consumption during peak demand periods. To avoid such a signal, TNUoS demand charges are ‘floored at zero’. This means that even if the charging model calculates that they should receive a credit, the lowest locational demand charge any user will face is zero. While this avoids potentially inefficient distortions to dispatch, it also distorts an important investment signal for sources of demand (including storage charging) in some locations.

As a result, storage assets face a mismatch between a cost reflective generation locational signal reflecting their impact from generation on increasing constraints and a distorted demand locational signal that does not reflect their impact from charging on relieving congestion. SSE has proposed a code modification (CMP405) to improve the cost reflectivity of the locational signals faced by storage. CMP405 aims to pay a demand credit based on Year Round costs, to reflect the fact that, outside of times of peak demand, demand from storage can reduce the volume (and the cost of managing) network constraints and thus reduce the need for investment.[2]

In this summary, Frontier and LCP consider:

- the benefits case for CMP405; and
- set out the possible options for designing a CMP405 demand credit.

1.3 The benefits case for CMP405

There is a clear defect in the current TNUoS charging methodology linked to the application of “floored at zero”, which prevents demand assets in locations close to large sources of generation from receiving a fully cost reflective locational charge. As a result, storage assets can face a mismatch between a cost reflective generation locational signal reflecting their

1 Northern Scotland, Southern Scotland, North West, Yorkshire, North Wales & Mersey, East Midlands

2 CMP405 can be considered as a first step towards further adjustments to the charging methodology to address this issue for other sources of flexible demand.

impact from generation on increasing constraints, and a distorted demand locational signal that does not reflect their impact from charging on relieving constraints.

The principle behind CMP405 is to address this defect for storage assets, increasing the cost reflectivity of the overall TNUoS charging methodology.[3] The focus of CMP405 on storage reflects a need to ensure efficient locational signals for the current pipeline of storage assets taking final investment decisions in the next few years, particularly some LDES that aims for final investment decision in the next year or two.[4] The government has stated that it will develop appropriate policy to enable investment in large scale long duration storage by 2024.

However, CMP405 should be considered as a first step. It will be important to continue the process of reform in order to support the development of other sources of demand as tools for minimising network costs.

We have used LCP's EnVision dispatch model to demonstrate the benefits that storage assets located In Scotland can have on relieving constraints. We have modelled 2025-2050 in five year increments, with each year modelled under 5 different weather years. This was to show the extent to which storage typically charges during periods of constraints and thus the contribution its charging makes to relieving those constraints.

The modelling tested a range of storage durations as a potentially significant factor in the ability of storage charging to relieve constraints, in both North and South Scotland. North Scottish storage is assumed to be located behind the B2 boundary and South Scottish storage assumed to be located behind the B6 boundary. This charging behaviour for North Scottish storage is shown in Figure 1, for storage with durations of 23 hours and 8 hours. This analysis also demonstrates that the extent to which storage assets are able to charge during periods of constraint does vary according to its duration. Similar results in percentage terms were found for Southern Scottish storage.

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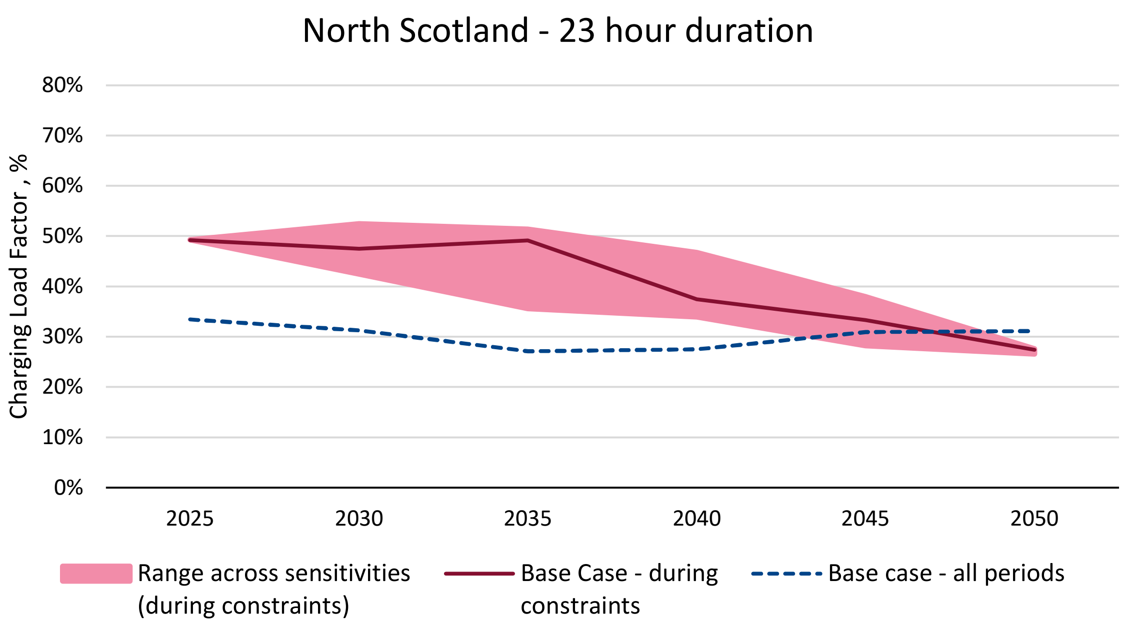
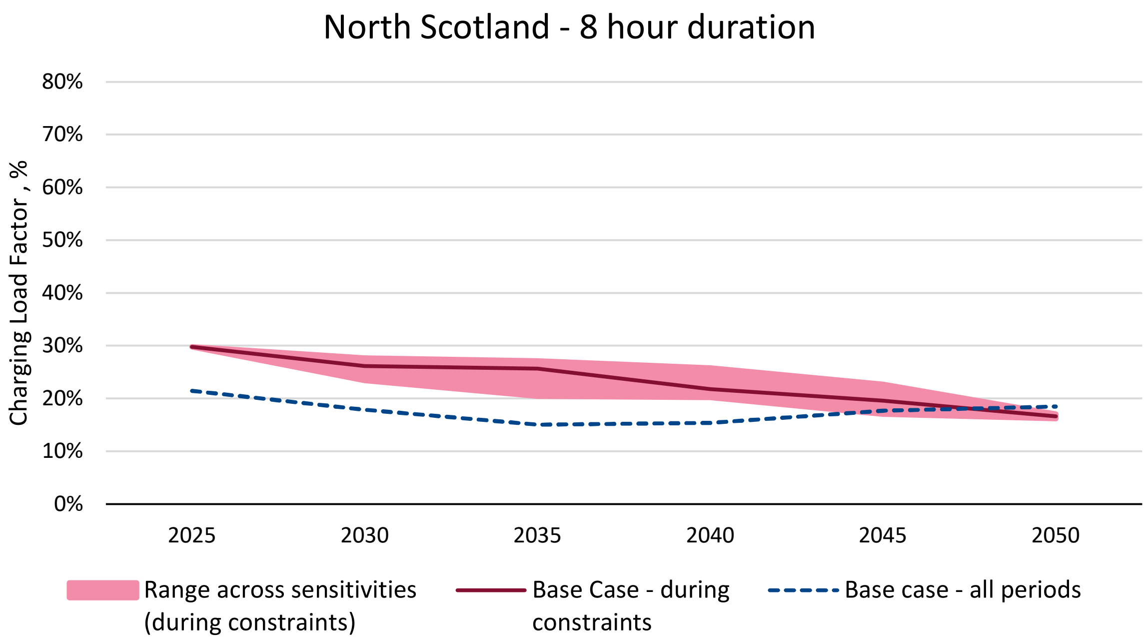
3 CMP405 enable storage assets to receive a cost reflective demand locational signal without introducing an incentive for storage assets to increase demand during times of peak demand. Thus, its introduction would not conflict with the logic that saw the introduction of floored at zero policy in the first place.

4 BEIS. Facilitating the deployment of large-scale and long-duration electricity storage. Government Response', (August 2022) page 6

Figure 1 Storage charging load factor during constraints





Source: *LCP Delta*

Note: *This chart shows the results for 23 hour and 8 hour storage in the North Scotland area during periods of constraints. Our analysis shows a similar picture for storage assets in the South Scotland area, and lower load factors for shorter durations*

As a result of its charging behaviour, storage assets located behind a network constraint are able to capture energy that would otherwise be curtailed (typically energy from wind plants) and dispatch that energy in other unconstrained periods. This behaviour can reduce the need for network investment, and reduce fuel use and carbon emissions as the stored energy displaces other more expensive generation (e.g. gas).

When assessing the case for CMP405, Ofgem will typically want to consider the impacts of the proposal on system costs and consumer costs.[5] Ultimately, it is difficult to identify the optimal level and location of investments by generation, storage and demand. However, if network charges are cost reflective, market participants should internalise their impact on future network costs into their investment decisions, leading to a more efficient pattern of investment.

By ensuring TNUoS charging accounts for the impact storage charging has on relieving network constraints, CMP405 should lead to more efficient investments. This applies to investment in new and existing storage assets as well as to more efficient closure decisions. To the extent that CMP405 results in a different pattern of investment, overall system costs should be reduced.

Our modelling demonstrates that with additional investment in storage in Scotland there could be significant reductions in the cost of operating the system. We compared a *counterfactual scenario*, based on NGESO'S FES22 System Transformation with no new build LDES capacity, with two factual scenarios:

- Factual Scenario 1 (FS1) assumes that CMP405 results in an additional 3.8GW (61.2GWh) of LDES being deployed by 2050 consistent with NG ESO FES22 leading the way scenario; and
- Factual Scenario 2 (FS2) assumes that an additional 3.8GW (17.5GWh) of short duration energy storage (SDES) is deployed by 2050.

The operational system costs were reduced in both factual scenarios, although the benefits are greater with more LDES compared to SDES, demonstrating the additional value that the storage capability of LDES provides to the system, over and above an equivalent capacity of SDES. The impact of equivalent storage capability was not modelled.[6] FS1 shows system cost savings of between £250m to £430m per year between 2035 and 2050 and average carbon savings of 0.085 $MtCO_2$ per year. In contrast, FS2 provides around £90m to £190m of annual system cost savings and 0.038 $MtCO_2$ of carbon savings.

If the electricity system with CMP405 is more efficient, then on average and in the long run, we would expect system cost savings to feed through into aggregate consumer cost savings. However, in the short and medium term the impact on consumers is uncertain, as it depends on multiple factors related to the existing structure of the electricity market and can be different

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5 *System costs* capture the total cost of all resources (capex and opex, including fuel costs and carbon costs) used in the electricity system to allow demand to be satisfied. *Consumer costs* are those that end users will face (e.g. wholesale costs, policy costs, network costs and balancing costs).

6 Equivalent capacity was compared rather than storage capability as it was envisaged that a demand credit would apply to capacity. If equivalent storage capability were used it would show a higher saving for SDES.

to system cost impacts because reforms can result in transfers of value between producers and consumers.

Different components of consumer costs will also be affected differently. For example, the charging behaviour of storage should result in the ESOs balancing and constraint costs reducing.[7] However, by reducing the volume of curtailed energy there will be an offsetting effect due to an increase in support payments to those otherwise curtailed plants. Although, this additional low carbon energy potentially reduces strike prices for future investors and reduces the need for other low carbon capacity to be supported as part of the transition to net zero. There are also other affects to consider related to wholesale prices, and network charges.

Our modelling shows that on balance there is an overall saving in consumer costs associated with constraints, wholesale costs and some support costs. Our central results show that from 2035 to 2050 in FS1 and FS2, the improved operational efficiency benefits result in an annual average consumer cost saving of £240m per year and £130m per year respectively. Not all consumer costs were modelled. For example, modelling of support for low-carbon thermal generation (hydrogen and CCUS) and the capacity market could result in further reductions in consumer costs. However, the cost of the demand credit itself would increase consumer costs.

The modelling presented in this report can help to inform the nature, direction and broad magnitude of potential effects of the modifications being considered. However, the modelling outputs we present do not consider all aspects of system and consumer costs, and depend on assumptions about a number of inherently uncertain input variables (e.g., fuel prices, demand). Such outputs are best used to complement a more principles-based assessment of the likelihood of modifications better facilitating objectives.

Overall, our modelling demonstrates the potential value that different types of storage can bring to relieving congestion, supporting the case for CMP405. However, it will be important that sound economic principles form the basis of the final decision in relation to any changes to network charging arrangements. Such principles relate to minimising distortions, fairness, and practical considerations. Charging in a manner consistent with such principles should help ensure an optimum outcome for society as a whole.

Based on our assessment, the introduction of a CMP405 demand credit would better align the TNUoS charging framework with these principles and therefore it is appropriate for CMP405 to be taken forwards.

7 This is because storage charging in response to wholesale market signals can reduce the volume of energy that needs to be curtailed, and because storage can be bid to charge more cheaply than paying supported wind to be curtailed this reduces the cost of managing the constraint. We note that generation from storage may also increase constraint costs, behaviour which is already reflected in its generation network charge.

1.4 CMP405 design options

The design of a demand credit under CMP405 should aim:

- not to distort otherwise efficient dispatch incentives; and
- to reflect the extent to which different assets contribute to the relief of constraints.

The principle of non-distortion implies that the credit should not be volumetric. Capacity-based charges would be simple, have precedent in the wider TNUoS charging regime and would mitigate the risk that the storage operator’s dispatch decisions were altered by the calculation of the credit.

Following the precedent of TNUoS generation charges, the size of the credit could be based on the zonal Year Round charge (in £/kW) and the storage operator’s import capacity, derated by a measure of its demand load factor.

Using a simple measure of a storage asset’s annual average demand load factor as the ‘derating factor’ would be closely analogous to the approach the TNUoS charging methodology takes to the charges paid by conventional generation assets which pay a Year Round charge based on their transmission export capacity (TEC) multiplied by their average annual load factor (ALF).

Alternatively, to make the size of the credit more reflective of the contribution of storage to relieving network constraints, the 'derating factor' could be set by the storage asset’s expected load factor during constraint periods, a ‘constrained ALF’. This would be analogous to the approach the TNUoS charging methodology takes to setting charges for intermittent plants using ‘sharing factors’. This ‘constrained ALF’ approach would likely imply a different level of demand credit for SDES and LDES, reflecting their different contribution to relieving constraints, as illustrated in our modelling.

2 Introduction

GB electricity transmission network charges have two components: a locational charge that reflects the cost that network users impose on the system and a cost recovery charge that allows transmission network owners to recover the cost of installing and maintaining the transmission system in Great Britain and offshore. The focus of this report is on the cost reflective locational element of TNUoS charges.

Current GB locational transmission network charges (TNUoS) are intended to reflect the “forward looking” network costs triggered by incremental connections of generation, demand and storage to the network. The charges aim to send efficient signals to generation and demand users by internalising the costs they impose on the network (or the benefits they provide).

These charges are set using National Grid ESO’s ICRP “Transport Model" with two “generation backgrounds”, introduced as part of Project TransmiT, reflecting the fact that:

- some transmission assets ensure peak security (“peak security” considerations); and
- each TO also makes trade-offs between expected constraint costs and the cost of reinforcements (“Year Round” considerations).

Given this, the charges are split into three parts, Peak, Year Round, and Residual charges. Residual charges allow cost recovery of the allowed revenue and are added to the locational transport tariffs. The residual charges are non-locational.

When project TransmiT introduced the peak and the Year Round components into TNUoS charges, the Year Round part was intended to proxy for the impact of production and demand outside of peak periods on constraint costs.

In general, a generator connected to a part of the network that is further away from demand, would pay a relatively high charge for locating there, and sources of demand will face higher costs if they connect to a location that is further away from sources of supply. Conversely, a source of demand that connects near generation should receive a credit reflecting the fact that their locational choice reduces the need for additional transmission network build.

Demand users are charged (or credited) TNUoS charges based on their load during periods of peak demand. Combining this charging approach with negative implied charges in some locations implied that some demand users would be paid to increase consumption at times of peak demand. Concerns about this outcome led to Ofgem flooring demand charges at zero to prevent users being paid to consume at peak. However, this flooring of demand charges at zero distorts final TNUoS charges and means that an important investment signal for demand in some locations is currently missing from final charges.

As a result, SSE has proposed CMP405 to address this distortion and missing investment signal. Their proposal would adjust the Year Round tariff to more accurately reflect the benefits provided by demand from storage in relieving network constraints. If accepted, CMP405 would be implemented by 01 April 2025.

SSE has appointed Frontier and LCP Delta to assess the case for CMP405 and make suggestions for its design. Our report is structured as follows:

- in Section 3, we describe the current arrangements for GB locational TNUoS charges (with a focus on reforms to TNUoS that serve as the context for CMP405) and discuss the particular motivation for CMP405;
- in Section 4 we set out the conceptual framework for an assessment of CMP405 from the point of view of system and of consumer costs (relative to a “no change” counterfactual) and describe qualitatively the potential implications of CMP405 for system and consumer costs;
- in Section 5, we set out our quantitative analysis, describing our modelling approach (including LCP Delta’s Envision model), our key modelling assumptions and our results; and
- in Section 6, we set out options for the high-level design of the CMP405 demand credit.

3 Background and motivation for CMP405

To understand the motivation for CMP405, it is helpful to understand the general approach to transmission charges in GB, and the particular concerns with the current regime that CMP405 is trying to address. The key messages for this section are set out below.

Key messages – Motivation for CMP405

- Locational network charges are set to incentivise efficient locational investment decisions for all market participants. Therefore, sources of demand located closer to generation should face lower costs than sources of demand located further away.
- Project TransmiT resulted in tariffs which separately recognised the impact that market participants have on network investment needed to provide peak security and to relieve constraints (so called “Year Round” costs). Transmit focused on the implications of different generators for Year Round costs. However, there appeared to be no explicit consideration with respect to demand.
- Following the TCR, efficient investment incentives were distorted as a result of the decision to floor locational demand charges at zero that would otherwise be negative. This meant an important investment signal for demand to locate in negative locational demand charge zones was removed.
- As a result, storage currently pays for the impact that its generation has on network costs through its generation charge, but it is not rewarded for network cost savings due to its charging behaviour.
- CMP405 would resolve this distortion by paying a demand credit based on Year Round costs, reflecting the contribution that demand from storage operators can make to relieving constraints and reducing the need for investment in network.
- CMP405 should be considered as a first step towards resolving the issue for other sources of demand.

In the rest of this section we:

- provide an introduction to the current approach to setting transmission charges in GB;
- set out the recent reforms to TNUoS that serve as the context for CMP405; and
- explain the particular motivation for CMP405.

3.1 Introduction to transmission network charges

In GB a system of locational network charges is applied to all users of the transmission network, with the objective of incentivising efficient locational investment decisions for market participants (generation, storage and demand) connecting to the network.

The locational charges reflect the principle of "cost reflectivity", meaning that charges paid by network users should reflect an estimate of the (forward looking) incremental costs they impose on the network through a change in their network use. The aim is that users internalise these costs in their decision making. For example:

- generation investors will face higher expected costs if they connect to a part of the network which is further away from demand; and
- sources of demand will face higher expected costs if they locate further away from sources of supply.

The incremental costs associated with different locations on the network are derived using National Grid's proprietary DCLF ICRP Transport Model,[8] which estimates a marginal investment cost for each transmission node across GB. Zonal generation charges, faced by users, are calculated by averaging nodal charges within each of the generation charging zones to arrive at 27 zonal generation charges. A similar approach is taken to calculate demand charges, but demand charges are calculated for each of the 14 demand charging zones. For generators, the final charge is adjusted by technology reflecting the costs that different types of generators impose on the transmission network[9] and is made up of a peak a Year Round and a residual charge.

For demand, the locational charge is levied based on consumers' peak demand. However, due to a concern about distortions to dispatch decisions in zones which would in theory have a negative demand charge, these charges are "floored at zero". This means that an important investment signal to locate demand in zones that would be helpful for relieving congestion has been lost. CMP405 aims to remove this distortion and we return to this below.

The costs recovered by the transmission network owners from locational network charges are unlikely to recover sufficient revenue to cover all of their allowed revenue. Therefore, additional "residual" cost recovery charges are levied in such a way as to minimise distortions to behaviour. This is to ensure that the investment or operational outcomes that result from the cost reflective charges are unaffected. In GB residual charges are only recovered from demand and average generator charges are capped at €2.50/MWh. If average locational generation charges exceed this cap (which they often do) then a flat adjustment tariff is paid to all generators in order to reduce average charges to the level of the cap. This is funded by increasing the demand residual.

3.2 Context and background to CMP405

The existing TNUoS charging regime (the Investment Cost Related Pricing (ICRP) methodology) traces its origins back to the 1990s. It has been reformed a number of times, including through the incorporation of load-flow analysis, and extension of its geographic

8 https://www.nationalgrideso.com/industry-information/charging/tariff-model-tnuos#:~:text=(DCLF%20ICRP%20Transport%20Model),demand%20tariffs%20under%20different%20scenarios.

9 Generators that operate more frequently generally impose higher costs than those that operate less frequently.

scope to incorporate Scotland. It is two of the more recent reforms which provide the context for CMP405:

- Project TransmiT intended to better reflect the changing electricity generation mix and the impact that different users had on transmission investment decisions; and
- Ofgem's Targeted Charging Review (TCR) required zonal demand charges that would otherwise have been negative to be "floored at zero", removing the possibility of negative triad demand charges.

We discuss each of these reforms and their relevance to this report in turn.

3.2.1 Project TransmiT

Project TransmiT followed changes to the Security and Quality of Supply Standard (SQSS), and in particular, the introduction of a second criterion for the assessment of future network capacity requirements. Following the changes, the SQSS applied a Demand Security Criterion and an Economy Criterion to assess future capacity requirements:

- the Demand Security Criterion requires sufficient transmission system capacity such that peak demand can be met through generation sources as defined in the Security Standard (typically conventional generation);[10] and
- the Economy Criterion requires sufficient transmission system capacity to accommodate all types of generation in order to meet varying levels of demand efficiently, seeking to identify an appropriate balance between constraint costs and the costs of transmission reinforcements.[11]

At the time of approving the change to the SQSS, Ofgem noted that the change would result in "required" transmission capacity which was closer to the level which would be determined by a full CBA.

This logic was reflected into TNUoS charges through Project TransmiT, with the introduction of the two sub-components of locational charges, determined through two separate "generation backgrounds":

- the peak security background identifies those network elements dimensioned to ensure peak demand can be met reliably, and the costs of reinforcing these elements is captured in the Peak Security element of charges; and
- the Year Round background identifies those network elements dimensioned on the basis the balance between constraint costs and the cost of incremental transmission capacity, and the cost of reinforcing these elements is captured in the Year Round element of charges).

10 https://www.ofgem.gov.uk/sites/default/files/docs/2011/08/nget-presentation-slides---28-july-event_0.pdf (page 3)

11 https://www.ofgem.gov.uk/sites/default/files/docs/2011/08/nget-presentation-slides---28-july-event_0.pdf

Project TransmiT also resulted in changes to generation charges in order to recognise that:

- some types of plant are not assumed to provide peak security, and that plant contribute to constraints differently by technology; and
- the generation mix in an area would determine whether transmission capacity between that and other areas could be "shared" (e.g. because the generation was expected to operate at different times).

In contrast, for demand, the implicit assumption was likely that any demand only caused costs, or benefits related to peak security requirements and no assessment of the potential for causing, or avoiding congestion cost, or for "sharing" network capacity was made. The problem with this is that once the charges were "floored at zero" due to them being levied at peak times, the locational signal reflecting the contribution to relieving constraints by demand was lost.

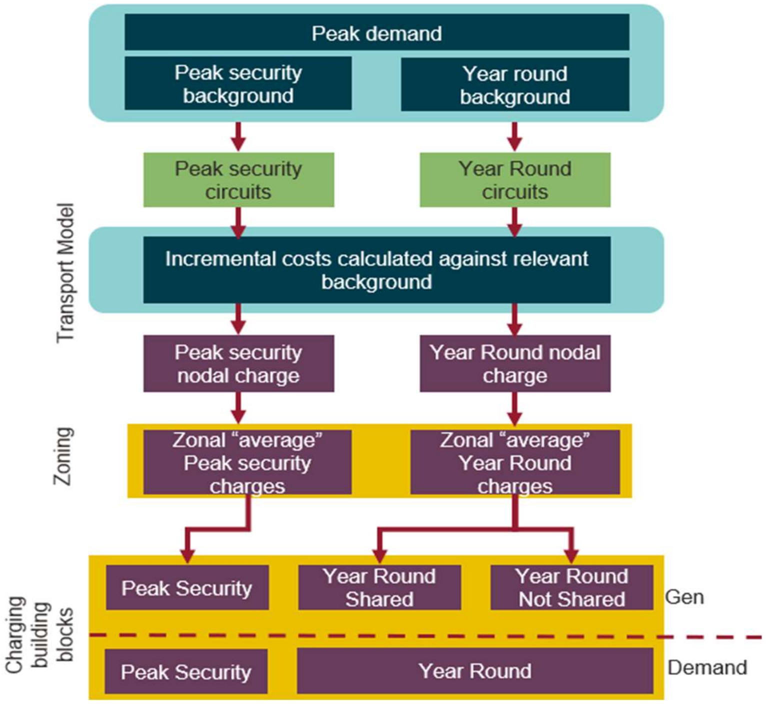
In its conclusions to Project TransmiT, Ofgem stated that, following the reforms, TNUoS charges:[12]

- more accurately reflected the economic trade-off each Transmission Owner makes between expected constraint costs and the cost of new transmission reinforcements when planning investment activity ("Year Round" considerations); and
- reflected the fact that some transmission assets are provided to ensure peak security (which does not rely on intermittent generation).

We briefly describe below how in practice these changes flow through into the calculation of locational TNUoS charges (as illustrated in Figure 2).

12 https://www.ofgem.gov.uk/sites/default/files/docs/2012/05/transmit-scr-conclusion-document_0.pdf page 16

Figure 2 Calculation of TNUoS Charges



Source: Frontier Economics

First, the Transport Model is used to estimate flows over the network given a measure of peak demand and two different generation profiles, with the technology mix in each set according to the CUSC.[13] For each background, the network is assumed to be able to accommodate these flows. Each network circuit is then 'tagged' to the background that drives the highest flows over that circuit i.e. the background which represents the 'cost driver' for that circuit.

The incremental expansion of the network required to accommodate users connected at each node is then calculated by modelling the change in transmission capacity required when 1MW of generation capacity is added at a node, matched by a 1MW increase in demand spread across all nodes. This calculation is performed for each background. Estimated Year Round and Peak Security incremental costs at each note are then calculated by multiplying the modelled incremental expansion of the network (in units of MWkms) under each background by an expansion constant.[14] Incremental demand costs are simply the inverse of the generation costs at each node.

Peak Security and Year Round charges for each of the 27 generation and 14 demand zones are then calculated by taking a weighted average of the implied nodal charges. These are then converted into final generation and demand charges:

13 https://www.nationalgrideso.com/document/91411/download. Para 14.15.7

14 The Expansion Constant (EC) is an element of the TNUoS charging methodology that determines the £/MW/km value of a 400kV Over Head Line (OHL). Source : https://www.nationalgrideso.com/document/178981/download

- for generation, the charge is split up into a Year Round charge which is in turn split into shared and non-shared elements based on share of low carbon generation in zone, and a peak charge. Technology-specific generation charges are calculated from these building blocks; and
- For demand, charges are simply based on the sum of Peak and Year Round charges.

The primary focus of Project TransmiT was on reforming generation charges, creating explicit recognition that some types of plant are not assumed to provide peak security and different types of plant trigger different levels of constraint cost. It does not appear that explicit consideration was made with regards to how the lessons from TransmiT regarding security, congestion and sharing, should be applied to demand charges.

3.2.2 Targeted Charging Review (TCR)

Following Project TransmiT, the total charge (locational charge and residual) for demand was "floored at zero", in order to ensure that no users faced an incentive to increase consumption during peak hours. In practice, given the large positive residual component,[15] total charges were positive even in zones with negative locational charges. The "floored at zero" policy did not impact on the operational and investment signals faced by demand sources.

- ***Operational efficiency*** – while the total charge faced by demand in a negative locational demand charge zone was lower than in a positive locational charge zone, given the total charge was always positive, there was no inefficient incentive for increasing consumption at peak; and
- ***Investment efficiency*** – since demand in negative locational demand charge zones faced a lower total charge than demand in positive demand zones, there was an incentive to focus demand investment in those zones.

As part of its TCR, Ofgem changed the structure of the residual charge, moving from a charge based on triad demand, to a fixed annual charge. This was motivated by the desire to reduce the incentive provided by residual charges for triad avoidance behaviour, such as investing in behind the meter generation. As a result, there was a stronger possibility that sources of demand located in a negative locational demand charge zones would be paid to consume at peak. To avoid creating an incentive for demand users to increase consumption at peak Ofgem chose to floor locational demand charges at zero. While this approach ensured that inefficient consumption at peak was avoided, it also had an important implication for demand investment efficiency, because it narrowed the relative locational signal across all zones:

- ***Operational efficiency*** – the locational charge is floored at zero, so no sources of demand receive a payment for consuming at peak, avoiding inefficient consumption; but

15 This was large because the sum of all cost-reflective charges does not provide sufficient revenue for the regulated network companies to cover the allowed costs of investing in and running the transmission network.

- ***Investment efficiency*** – sources of demand in negative locational demand charge zones do not receive a credit related to the benefit of being located in the that zone, as they pay the same total charge as sources of demand in zones with a zero locational charge. This reduces the incentive to invest in negative locational demand charge zones.

3.3 The motivation behind CMP405

As a result of the reforms discussed above, sources of demand (including charging of storage) do not receive a cost reflective signal to invest in zones with negative locational charges. In principle, this applies in respect of both the Peak and Year Round element of charges.

CMP405 is focused on the charges for storage plants. Storage will not typically consume power during triad periods and therefore, will face zero demand locational charges in respect of both Peak and Year Round elements. For the Peak element of charges, this is reasonable because triad periods reflect periods of peak system demand and thus if storage is not charging in peak demand periods, it should face no demand charge (credit) for doing so.

The Year Round element of charges is intended to reflect the impact of demand on the costs of network elements that ensure a balance between network investment and constraint costs. These impacts primarily relate to demand load during the course of the year and outside triad periods. However, because charges are floored at zero and levied based on consumption in triad periods (when sources of demand will likely have minimum consumption) demand sources do not receive any recognition of their contribution to reducing Year Round network costs.

Project TransmiT explicitly recognised the value of avoided Year Round network costs, and therefore the scale of the missing investment signal can be clearly identified. In practice, as shown in **Error! Reference source not found.**, TNUoS tariffs for 2022/23 indicate that there are many instances of negative locational demand tariffs in northern zones, and that Year Round costs are particularly important in the Scottish demand zones.

Figure 3 Peak and Year Round TNUoS tariffs, 2022/23

Demand Zone		2022/23 Draft		2022/23 Final	
		Peak (£/kW)	Year Round (£/kW)	Peak (£/kW)	Year Round (£/kW)
1	Northern Scotland	-2.378353	-26.865706	-2.178226	-27.236880
2	Southern Scotland	-2.666540	-18.568727	-2.588187	-18.807862
3	Northern	-4.209072	-7.936630	-4.334540	-7.845295
4	North West	-1.526881	-3.955356	-1.522583	-3.931676
5	Yorkshire	-3.069356	-1.950554	-3.111358	-1.910980
6	N Wales & Mersey	-2.178954	-1.558879	-1.977716	-1.477330
7	East Midlands	-2.747019	1.428389	-2.753986	1.420681
8	Midlands	-1.364659	1.715097	-1.348947	1.681051
9	Eastern	0.473848	0.632420	0.445125	0.646597
10	South Wales	-3.503913	5.121186	-3.519338	5.119538
11	South East	3.648368	-0.295570	3.640164	-0.302852
12	London	4.511476	2.329373	4.486793	2.339230
13	Southern	2.541405	2.876418	2.537729	2.864165
14	South Western	1.925710	4.976812	1.880963	5.004935

Source: Final TNUoS Tariffs for 2022/23, January 2022,Table 20

CMP405 is focused on demand from storage units. Its objective is to more accurately reflect the locational signals produced by the model in final users' tariffs. In particular, it would resolve the distortion that results from the "floored at zero" aspect of the charging methodology by paying a credit linked to the value of the Year Round charge to storage in negative locational demand charging zones, in a manner that is decoupled from triad demand (i.e. not linked to actual consumption at time of system peak demand.[16]

As discussed above, the distortion arising from "floored at zero" also applies to other sources of demand. As a result, while CMP405 addresses an investment distortion between positive and negative charging zones, it potentially creates a new distortion between storage and other forms of demand. It should therefore be considered a first step in addressing the wider issue, reflecting the importance of ensuring efficient locational signals for the current pipeline of storage assets given BEIS's commitment to a implementing a policy to enable investment in long duration storage by the end of 2024.[17] It will be important to continue the process of reform in order to support the development of other sources of flexible demand as tools for minimising network costs.

16 https://www.nationalgrideso.com/document/271461/download

17 BEIS. Facilitating the deployment of large-scale and long-duration electricity storage. Government Response', (August 2022) page 6

We note that other related modifications (e.g. CMP393) have also been proposed to incentivise storage to connect, but that they do not directly address the ‘floored at zero’ distortion.

4 Assessing the benefits of CMP405

Consistent with public sector policy appraisal best practice, we now consider qualitatively the implications of reform under CMP405 for both system and consumer costs, relative to a counterfactual (the absence of CMP405).

To do this, we:

- first, set out the conceptual framework typically used (based on that used for assessing similar charging reforms); and
- second, we describe the potential implications of CMP405 for system and consumer costs.

We first set out the key messages from this section.

Key messages – Section 4

- The purpose of CMP405 is to address the distortion created by "floored at zero" so storage faces more cost reflective network charges.
- If storage located behind constraints typically charges during periods of constraints, then it is able to capture otherwise curtailed energy and dispatch it into another time period when there is either more local demand or the network is less congested. As a result, network investment could be avoided, and fuel use and carbon emissions reduced.
- By rewarding storage assets for their impact on relieving network constraints, CMP405 should lead to more efficient investment in new and existing storage assets and more efficient closure decisions. These decisions are facilitated by tariffs that are more cost reflective.
- To the extent that CMP405 results in a different pattern of investment, overall system costs should be reduced.
- In the long run, we would expect system cost savings to feed through into aggregate consumer cost savings. However, in the short and medium term the impact on consumers is uncertain, as it depends on multiple factors related to the existing structure of the electricity market and can be different to system cost impacts because reforms can result in transfers of value between producers and consumers.

4.2 Conceptual framework for assessment

To assess the impacts of reform it is common to consider the potential implications under two main categories:

- electricity "whole system" costs, and
- electricity consumer costs

We consider each of these in turn, and then consider their relevance for Ofgem's primary objectives.

4.2.1 Whole system costs

A reduction in whole system costs between the factual and counterfactual implies an increase in social welfare. System costs are the costs of all the resources used to satisfy demand for electricity including generation, networks and connection costs. These cover both investment and operational costs.

Investment costs include:

- generator capital expenditure;
- network capital expenditure;
- cost of capital impacts; and
- other costs associated with running of system or participating in the system e.g. IT and institutional costs.

Operational costs include:

- fuel costs;
- variable operating and maintenance costs; and
- carbon costs.

A reduction in whole system costs between the factual and counterfactual implies an increase in social welfare, because society is using fewer resources to satisfy demand.

4.2.2 Consumer costs

Consumer costs are the costs which consumers pay for their electricity. These include transfers between consumers and producers, and so are different to system costs (which do not include any transfers).

Consumer costs include:

- Balancing and constraint costs;
- wholesale costs of purchasing energy;
- network costs, including network charges and congestion rents; and
- support costs, including impact of changes on CfDs/ROCs and Capacity Mechanism, or any cap and floor regimes.

An increase in social welfare does not necessarily have to be associated with reduced consumer bills. In the short term, a measure can improve social welfare (reduce system costs) but result in increased costs to consumers, for example because it results in increased transfers to producers. Similarly, it is possible for there to be no system savings but reduced consumer costs (e.g. due to a policy that transfers producer surplus to consumers).

However, in the long run it is reasonable to expect overall welfare improvements to be passed through to lower consumer bills.

4.2.3 Ofgem's primary objectives

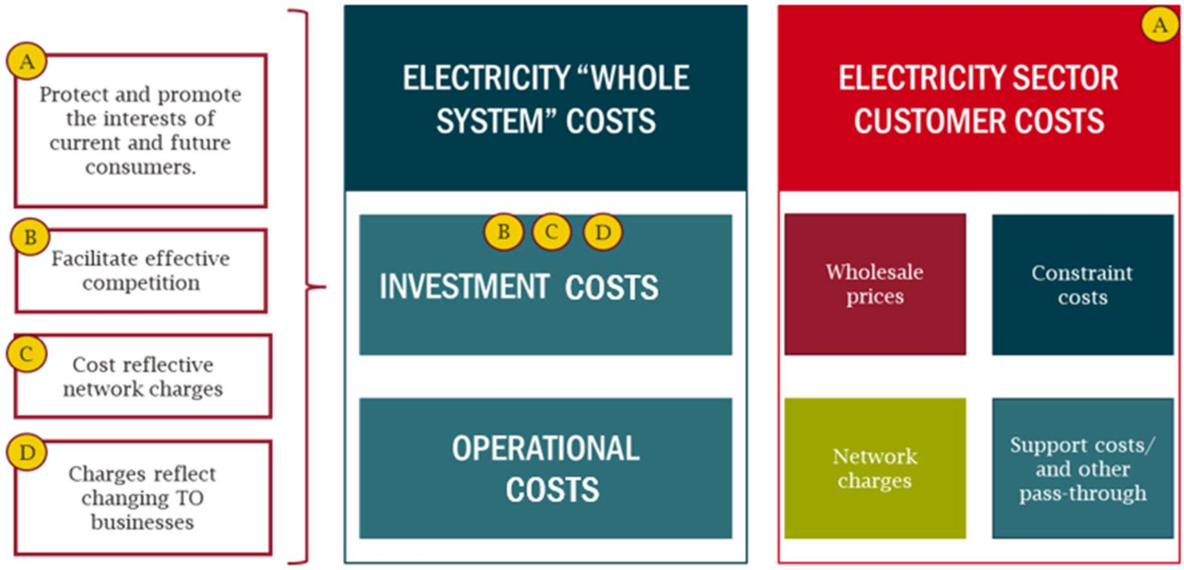
Ofgem's duties and the CUSC objectives will be relevant to any evaluation of CMP405. Among these, we have focused on four criteria that we consider are most relevant to CMP405. These are:

- protecting and promoting the interests of current and future consumers;[18]
- facilitating effective competition;
- having cost reflective network charges; and
- having charges that reflect changing TO businesses.

In Figure 4 below we show that the system and consumer cost framework captures each of those objectives, and therefore is appropriate for assessing CMP405.

18 Ofgem's principal statutory objective is to protect the interests of existing and future gas and electricity consumers. Currently this is clarified to include consumers' interests in the reduction of greenhouse gases emissions in electricity and gas supply. A proposed amendment to The Energy Bill currently in parliament would replace the greenhouse gas emission wording with a specific reference to protecting existing and future consumers' interests by supporting "*the Secretary of State's compliance with the duties 1 and 4(1)(b) of the Climate Change Act 2008 (2050 net zero target and five-year carbon budgets)*". If this amendment comes into force, we do not consider it would change the mapping of the objectives to the framework that we present below.

Figure 4 Mapping Ofgem's primary objectives to the system and consumer cost framework



Source: Frontier Economics

4.3 System cost impacts of CMP405

As we set out in the previous section, there is a clear defect in the current TNUoS charging methodology linked to the application of "floored at zero" which prevents demand assets in locations close to large sources of generation from receiving a fully cost reflective locational charge. The principle behind CMP405 is to address this defect for storage assets, increasing the cost reflectivity of the overall TNUoS charging methodology.

As we will discuss in Section 6 of the report, the intention is for CMP405 to enable storage assets to receive a cost reflective demand locational signal without introducing an incentive for storage assets to increase demand during times of peak demand. Thus, its introduction would not conflict with the logic that saw the introduction of floored at zero policy in the first place.

If storage assets that are located behind constraints typically charge during periods of constraints, then they are able to capture energy that would otherwise be curtailed (typically energy from wind plants) and dispatch that energy in another time period when there is either more local demand or the network is less congested. In Section 5 of this report, we demonstrate that this behaviour is to be expected, but its extent may be more significant for storage with longer durations.

This behaviour can:

- reduce the need for network investment as storage is able to store the energy for use in another unconstrained period making more efficient use of existing network capacity;[19]
- reduce fuel use and carbon emissions as the stored energy displaces other more expensive generation in unconstrained periods;[20] and
- capture more of the available low carbon energy (thereby increasing wind load factors) such that less low carbon capacity is needed in the long run to achieve net zero.

While storage is a substitute for network investment, it is important to note that it may not be a perfect substitute. This is because:

- network investment allows more energy to be moved between locations at any given time; whereas
- storage investment may allow more energy to be moved between locations, but only in periods after the energy has been produced, and only if the network is not congested in those periods.

In other words, the network benefits of storage investment are likely to be maximised as an alternative to marginal network investments when the level of spare capacity on the network is balanced such that there are both constrained periods and sufficient unconstrained periods.[21]

If network charges are cost reflective, market participants should internalise their impact on future network costs into their investment decisions, leading to a more efficient pattern of investment. By rewarding storage assets for their impact on relieving network constraints, CMP405 should lead to more efficient investments in new and existing storage assets and more efficient closure decisions.

Ultimately, it is difficult to identify the optimal level and location of investments by generation, storage and demand, therefore, by improving the cost reflectivity of tariffs the actions of market participants are more likely to achieve efficient investment, and this may result in additional storage investment that would otherwise have not been commercially viable. To the extent that CMP405 results in a different pattern of investment, overall system costs should be reduced relative to what would have happened absent CMP405.

The scale of benefits from CMP405 are therefore likely to depend on:

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19 This is reflected in the model by the flows expressed in MWkm. A negative MWkm indicates that flows are reduced on the system by virtue of the location of the demand and, all other things equal, implies reduced network investment.

20 We note that within the traded sector of the UK ETS, carbon reductions in electricity are offset by increases in emissions elsewhere.

21 If there is little spare transmission capacity, then storage assets are unable to substitute for transmission build because there are few periods in which storage energy can be discharged. If there is lots of spare capacity, then storage assets are not needed to substitute for network build because there will be few congested periods for storage to move excess generation out of.

- whether the introduction of CMP405 demand credit creates a positive investment case for storage facilities that would otherwise have a negative investment case;
- the type of storage investments that occur – in particular, investments in long duration storage may be more able to act as a substitute for network build because they can transfer more power between constrained and unconstrained[22] periods than equivalently scaled short duration storage;
- the level of transmission system build; and
- the extent of spare transmission network capacity, both in terms of volume of spare capacity and duration of spare capacity.
- the volume of storage investments which change their intended location;

A CMP405 demand credit may also marginally reduce the cost of capital for storage investments in negative locational demand charging zones if it is expected to provide investors with a new stable stream of cashflows.[23]

When carrying out our quantitative analysis (detailed in Section 5) we consider the benefits of additional storage against the background of an optimised network, proxied for by a range of scenarios based on FES. [24]

4.4 Consumer cost impacts of CMP405

If the electricity system with CMP405 is more efficient, then on average and in the long run, we would expect system cost savings to feed through into aggregate consumer cost savings. However, in the short and medium term the impact on consumers is uncertain, as it depends on multiple factors related to the existing structure of the electricity market and can be different to system cost impacts because reforms can result in transfers of value between producers and consumers.

CMP405 may have impacts in each of the consumer cost categories we have set out above. We discuss each in turn below.

Some of these effects vary depending on whether CMP405 incentivises additional storage build or incentivises a storage build that would have occurred anyway to locate in negative demand charge zones. Where this is the case, we call out which impacts would be expected in each scenario.

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22 Constrained in this instance means when the ESO needs to take balancing actions because the unconstrained system optimisation in response to the national price signal implies greater generation within a zone than can be exported given transmission capacity.

23 The importance of this impact will depend on whether other support mechanisms are applied to storage which also result in more stable cashflows than merchant operation.

24 The actual network build will ultimately be informed by the Holistic Network Design Follow-Up Exercise, the future Centralised Strategic Network Plan, and Ofgem's Accelerated Strategic Investment regulatory framework.

Balancing and constraint costs

As mentioned above, storage assets located behind constraints can capture and dispatch energy in another time period when there is less congestion. The benefit of this is that balancing and constraint costs will be lower.

If CMP405 also leads to additional investment in storage capacity in negative locational demand charging zones, it could further reduce balancing and constraint costs, meaning consumers pay lower balancing costs (BSUoS).

The impact on the ESO's balancing and constraint costs could come from the following three sources.

- Firstly, there may be a change in the volume of energy that the ESO needs to curtail and redispatch.
  - If CMP405 leads to additional storage capacity in negative locational demand charge zones (whether this is a shift of investment or net additional investment), this capacity could lead to increased demand from storage at times of network congestion in response to wholesale market prices. If this is the case it would reduce the volume of resources (including potentially wind generation) which ESO would need to constrain off.
- Secondly, there may be a change in the cost of curtailing and re-dispatching energy.
  - Additional storage in negative locational demand charging zones may bid into the balancing mechanism to charge during periods of network constraint at a lower cost than alternative bids. This would reduce ESO's cost of managing constraints.
  - The extent of the saving realised in this way is dependent on the level of storage operators' bids. The closer bids are to the negative bids that some supported wind may submit into the BM, the smaller the saving.
- Thirdly, there could be changes in the cost of procuring ancillary services.
  - If CMP405 leads to a net increase in storage capacity then there may be additional competition in the ancillary services market, reducing ESO's cost of procuring ancillary services.
  - If CMP405 leads to a shift in storage investment from positive to negative locational demand charging zones (rather than a net increase in capacity), the resulting changes in competition in the markets could reduce ancillary services costs in negative charging zones and increase them in positive charge zones. The net impact of these changes is uncertain but is likely to be marginal.

There are also scenarios in which additional storage capacity in export constrained areas of the grid may increase ESO's costs. Storage will typically discharge in high wholesale price periods, and if these periods coincide with periods of network constraint then this could exacerbate constraints, resulting in a need for the storage, or other options higher in the merit order, to be constrained off. The extent to which this occurs depends on the correlation of periods of high national wholesale prices with network constraints.

However, for storage connecting in a positive generation charging zone (which will typically be the case for assets which are connecting in a negative demand charging zone), the positive generation network charge already reflects an estimate of additional network costs resulting from its expected discharging behaviour. Therefore, the risk of such behaviour does not weaken the case for CMP405.

Wholesale cost of purchasing energy

If CMP405 leads to additional investment in storage capacity which engages in intertemporal price arbitrage as one of its sources of revenue, this would lead to a 'flattening' of wholesale prices. Wholesale prices during low price periods may increase as storage charges, marginally increasing demand in these periods. Wholesale prices during high price periods may then reduce as storage discharges, displacing generation from more expensive sources.

The net impact of this flattening of wholesale costs of purchasing energy depends on two factors:

- the shape of the merit order in low priced periods and high price periods. If the merit order is relatively flat[25] then additional charging or discharging by storage operators is less likely to result in material changes to the wholesale price in that period; and
- the relative volume of energy consumed in lower and higher price periods.[26] For example, if demand is higher during high price periods and if the scale of change in wholesale prices is equal in each, then wholesale costs would reduce.[27]

If CMP405 leads to a relocation of storage investment, without additional capacity, then we would not expect it to have a material impact on the wholesale cost of purchasing energy.

Network costs, including network charges

The impact on network costs of CMP405 is likely to be similar whether it leads to additional storage capacity overall, or just a relocation of investment, but is likely to be different in the short term and the long term:

- In the short term the TNUoS demand residual would be higher in order to pay for the CMP405 demand credit; and
- In the longer term, if changes to storage investment result in avoided network investment total TNUoS charges should be lower.

[25] i.e. the SRMC of the technology at the margin does not change significantly as demand changes.

[26] There is likely to be a positive correlation between wholesale electricity prices and demand.

[27] Although uncertain, there is likely to be a positive correlation between wholesale electricity prices and electricity demand.

Support costs, including impact of changes on CfDs/ROCs, Capacity Market

The net impact on support costs is uncertain. Support costs payable to otherwise constrained wind generators are likely to increase, whilst support costs for other wind and other low carbon generation (e.g. CCS plant) are likely to fall.

Support costs may increase because an increase in support costs is likely to arise as otherwise curtailed renewable plants (primarily wind) will increase their running hours. Some of these plants are supported using volumetric support mechanisms (e.g. CfD) and thus higher load factors implies higher support payments for existing contracted projects. To the extent that these payments increase, they will be offset by the reduction in compensation payments for curtailment.[28] New projects may not expect to receive higher support payments due to running hours as they could adjust their strike price bids accordingly.

There are a number of mechanisms that could reduce the value of support costs:

- A decrease in support costs would tend to occur if the discharging of stored power by storage operators displaces the operational dispatch of other low carbon supported plants, such as CCUS, or biomass in the merit order.
- A decrease in support costs could tend to occur if the discharging of stored power by storage operators displaces investment in other low carbon sources of generation, such as displacing investment in capacity of other wind farms, or solar PV. This would reduce low carbon generation volume from other sources, therefore reduce support payments to other wind farms.[29]
- A decrease in support costs due to reduced frequency of low price periods. This could reduce Strike Prices by reducing the cost of negative price risk during CfD contracts. In addition, it could increase wind price capture prices, which could in turn both reduce the value of CfD top-up during CfD contracts, as well as reduce the value of CfD Strike prices, which would no-longer need to be as high to offset low price capture in the post CfD contract period.

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28 We note that supported renewable plants that lost support payments because they were curtailed in the BM will have received compensation for these lost revenues. Therefore, the net impact on consumers of the change in support payments and BSUoS costs for these actions is likely to be minimal. However, wind committed before storage FID decisions, which would otherwise have been curtailed because the national wholesale price reached zero or negative values, would not have been compensated and thus additional running hours for wind as a result of fewer periods with zero or negative wholesale prices will imply a net increase in support payments for these projects. Those after FID would be expected to take account of the change in CfD bidding behaviour.

29 A decrease in low carbon support cost could also occur if a higher total wind volume enabled GB to achieve net zero either sooner, or to a greater degree, which would tend to displace low carbon support costs in other parts of the energy system.

5 Quantitative assessment of the case for change

5.1 Introduction

The purpose of the modelling is to assess the potential benefits that storage of different durations may bring to the system in terms of constraint management. The modelling assesses the behaviour of storage during periods of constraint, and in particular its ability to act, through charging, as a flexible source of demand, capturing energy that would otherwise be curtailed to be usefully returned to the system at a later period. The modelling also explores how these benefits may be sensitive to different assumptions around the development of the power system, and how they may vary for different types of storage.

Note that this modelling does not constitute a full Cost Benefit Analysis (CBA) for the introduction of CMP405, but rather it is intended to demonstrate the potential benefits from introducing a CMP405 demand credit and whether those benefits are likely to be different for different types of storage depending on their duration. A full CBA can be done when there is a design available. However, this analysis considers many of the components that would be included in a CBA.

The modelling presented in this report can help to inform the nature, direction and broad magnitude of potential effects of the modifications being considered. However, the modelling outputs we present are dependent on assumptions on a number of inherently uncertain input variables (e.g., fuel prices, demand). Such outputs are best used to complement a more principles-based assessment of the likelihood of modifications better facilitating objectives. Such principles relate to minimising distortions, delivering fair outcomes, and practical considerations. Charging in a manner consistent with such principles should help ensure an optimum outcome for society as a whole.

We first list the key takeaways from the quantitative analysis and then in the rest of this section we cover:

- An overview of the modelling approach including an explanation of the cases and scenarios covered;
- The key modelling assumptions used in these scenarios around the development of the power system;
- Modelling results, including the wider system results, the behaviour of different durations of storage during periods of constraint, and the overall system impacts of additional storage; and
- A discussion of the conclusions from the modelling

We have included a description of the model used to conduct the analysis in Annex E.

Key messages – Section 5

- Our modelling shows that storage in export constrained zones tends to charge during periods of constraints, particularly when wind is being curtailed, supporting the cost reflectivity of the proposed CMP405 demand credit;
- Storage charging load factors during constraints, particularly when wind is being curtailed, are high, and significantly higher than their average annual charging load factors;
- Additional storage located behind constraints reduces operational system costs and feeds through into lower consumer costs;
- LDES located behind constraints has higher charging load factors and delivers a greater operational system cost reduction than the equivalent GW capacity of shorter duration storage;
- Longer duration storage leads to higher utilisation of renewable generation;
- As renewable generation capacity increases, LDES plays a key role in reducing wind curtailment by charging during constrained periods, ensuring that surplus wind generation can be put to good use;
- This analysis supports the view that storage acts in a beneficial way for relieving constraints, behaviour which it is currently not rewarded for through network charges;
- The conclusions are robust to different assumptions. The results were tested under a range of years (2025 – 2050) and across different assumptions for levels of wind deployment and network reinforcement.

5.2 Modelling approach

To illustrate the potential benefits of CMP405, we have been asked to run the analysis under five background cases. National Grid ESO's System transformation (ST) scenario is used as the basis for these five scenarios:

- **Base Case:** An adapted version of ST with a 5 year delay in offshore wind build, and an "optimised" network build (more detail in Annex B)
- **High Wind:** The ST scenario including an optimised network to efficiently accommodate the higher wind build
- **High Network Build:** Base Case with higher network build (from the High Wind sensitivity) i.e. a scenario with fewer constraints relative to an optimised network.
- **Low Wind:** The ST scenario including an optimised network to efficiently accommodate the lower wind build
- **Low Network Build:** Base Case with lower network build (from the Low Wind sensitivity)

More detail on the assumptions used in each of these background cases is provided in the next section and in Annex B.

For each background case we have run three separate scenarios for how additional storage capacity might be deployed in future:

- Counterfactual (CF): ST storage capacity assumptions but with new LDES removed
- Factual scenario 1 (FS1): CF with LDES included in line with the ST scenario (this assumes net additional storage investment attributable to the introduction of CMP405)
- Factual scenario 2 (FS2): CF with equivalent GW of shorter duration storage to the LDES included in FS1 (this assumes net additional storage investment attributable to the introduction of CMP405) – but with investment focussed on shorter duration storage, resulting in less additional storage in GWh terms when compared to FS1.

Each scenario is assessed using 5 simulations which cover a range of different weather and demand conditions. The results presented are the mean of these 5 simulations.

Using these scenarios, we can estimate the benefits that deploying LDES could provide to the system and compare this against the benefits associated with shorter duration storage, paying particular attention to the impact on transmission constraints.

We can use the modelling results to indicate the potential level of the CMP405 demand credit under different design options – this is presented in Section 6.

5.3 Modelling assumptions

5.3.1 Overview

The basis of our modelling assumptions is the System Transformation scenario from Future Energy Scenarios (FES) 2022, published by National Grid ESO,[30] with the following exceptions:

- Wind capacity – System Transformation delayed by 5 years in our Base Case
- Storage capacity – the level of LDES and battery storage capacity is the key distinction between the counterfactual and two factual scenarios

The FES scenarios do not include transmission network build assumptions. We have assumed transmission network build is optimised to minimise costs (including the capital cost of network reinforcement) as this is consistent with the TNUoS charging methodology. We describe this further in Annex B.4.

[30] https://www.nationalgrideso.com/document/264421/download

We note that FES 2023 has been published since this analysis was carried out. A summary of some the key assumptions and how they have changed between the System Transformation scenario in the 2022 and 2023 editions of FES is provided in Annex B.1.

5.3.2 Generating capacity

Capacity Mix

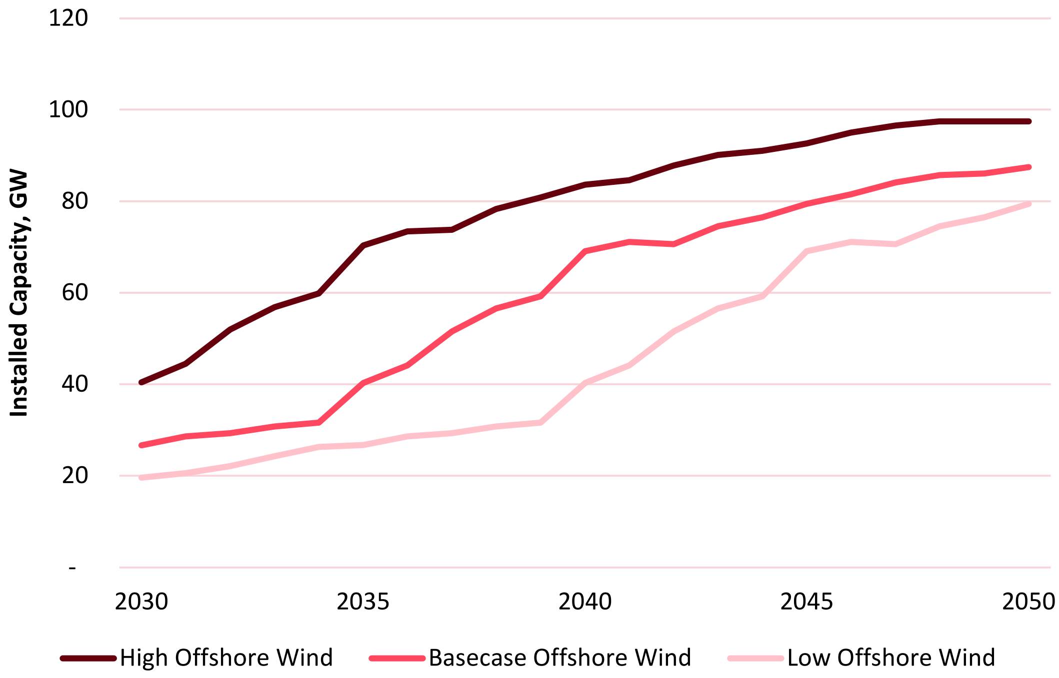
The System Transformation (ST) scenario is used as the basis for our capacity mix backgrounds. Annex B.2 shows the capacity mix assumptions used in the modelling.

Wind capacity

The ST scenario has a very high level of wind penetration, with offshore wind capacity increasing steeply to 73GW in 2035 and 116GW in 2050; this represents 100% of peak demand in 2035 and 115% of peak demand in 2050. Our modelling shows that, in 2035, this level of wind capacity results in wholesale prices at £0/MWh or below for 46% of the time due to significant periods of excess supply of variable renewable generation.

The ST scenario is a transparent scenario that meets the net target and is used by NG ESO for electricity system planning purposes. ST scenario is likely to result in many zero priced periods, which would require significant support top-up payments to generators with CfD support. In reality, a cost-optimised scenario is likely to have much lower levels of wind penetration, and we have therefore adopted a 5-year wind delay to build as our Base Case, which brings wind penetration levels down to around 60-70% of peak demand. This is more in keeping with the kind of wind penetration levels seen in cost optimised scenarios. We have also assessed the FES ST scenario as an additional sensitivity to understand how this higher level of wind penetration would impact on the results.

Figure 5 Offshore Wind Capacity



Source: LCP Delta

Note: This is the level of offshore wind capacity used across the scenarios. The Base Case level of wind is based off a 5 year delay of the ST FES scenario

In all our scenarios, we assume a lower proportion of new wind build connects into Scotland relative to the level assumed by the FES System Transformation scenario. ST indicates that 7GW of offshore wind connects to Scotland in 2030 and 35GW by 2050, whereas we assume only around half connects by 2050 (excluding the 5-year delay). This is to reflect the fact that many of the offshore wind projects in the waters around the southern part of Scotland will likely connect to the onshore network in England, so as to bypass the Scottish export constraint[31]. Based on seabed lease locations and factoring in the outcome of the Holistic Network Design (HND) process, we have assumed that around half of wind situated in Scottish waters connects into England.

Storage capacity

The Counterfactual assumes no new LDES build whereas Factual Scenario 1 assumes LDES capacity increases broadly in line with FES Leading the Way. Factual Scenario 2 does not assume any new LDES build, but it does assume additional shorter duration (2-8 hour) battery storage build equivalent to the capacity in MW of new LDES deployed under System Transformation, and according to the same time profile of investment. Battery storage capacity for FS2 is split evenly between 2-hour, 4-hour, and 8-hour duration assets. By fixing the capacity (GW) of long and short duration to be equal, we are modelling the impact of having

[31] https://www.offshorewindscotland.org.uk/the-offshore-wind-market-in-scotland/electricity-grid-in-scotland/

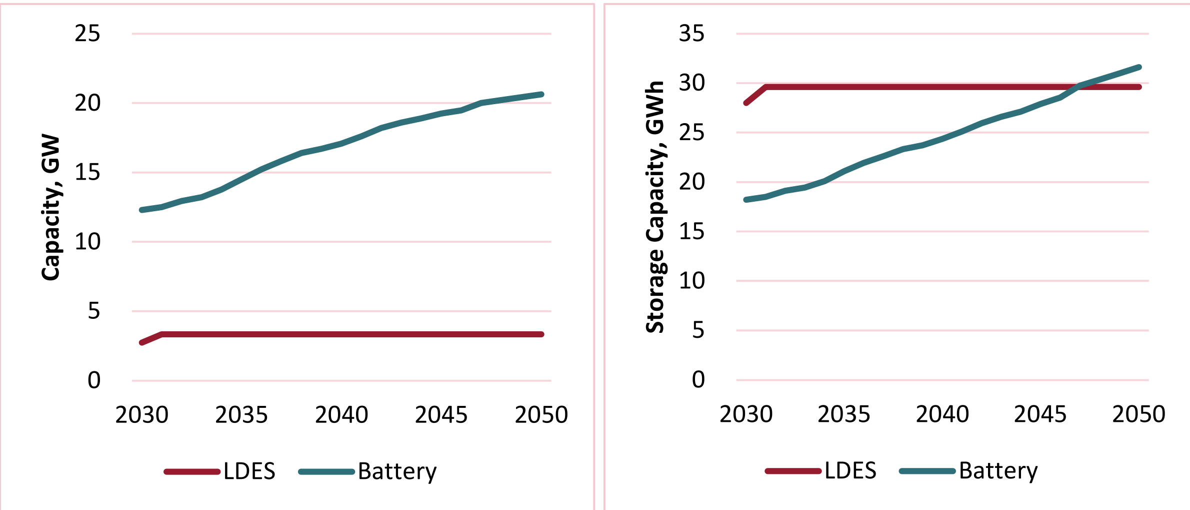
materially more storage capacity (GWh) in FS1 compared to FS2. This distinction between FS1 and FS2 is intended to highlight the benefit that long-duration storage can bring the system in terms of managing transmission constraints, in comparison to an equivalent GW capacity of shorter duration storage.

Battery storage capacity for FS1 is the same as the counterfactual scenario and LDES capacity for FS2 is the same as for the counterfactual.

It should also be noted that storage assets with durations of less than 8 hours are modelled as battery storage and those with durations of 8 or more hours are modelled as pumped storage, and therefore have a lower efficiency.

Charts are shown in Annex B.3 with the additional battery capacity modelled in the FS1 and FS2 scenarios.

Figure 6 Battery and Pumped Storage Capacity (GW and GWh) – Counterfactual

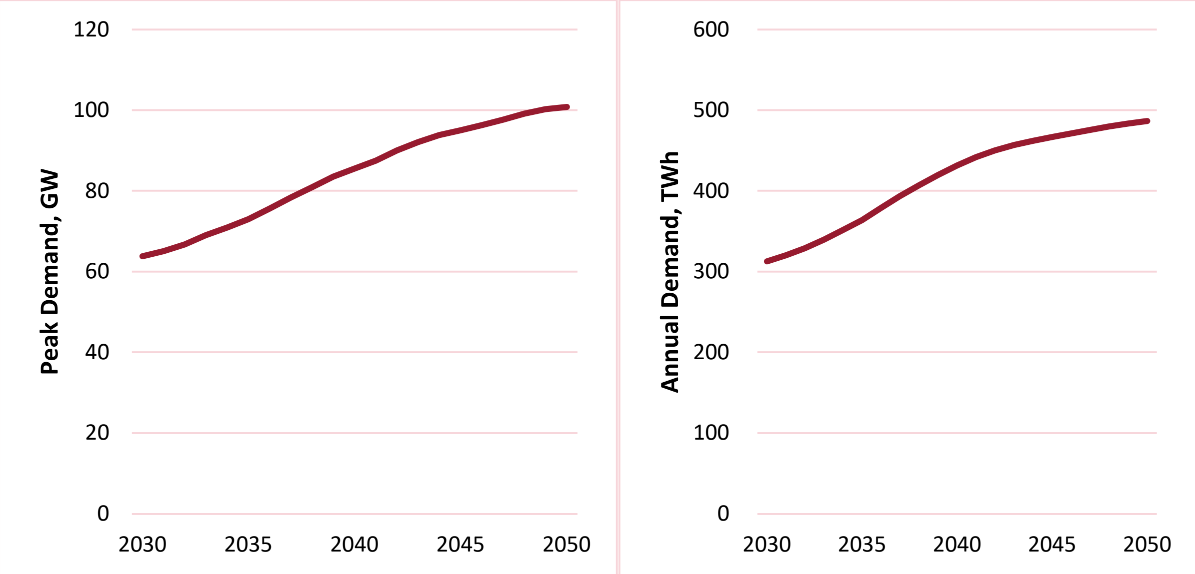


Source: LCP Delta
Note: These are the capacity assumptions for batteries and pumped storage in the counterfactual scenario

5.3.3 Demand

The demand assumptions remain in line with the ST scenario and are therefore consistent across all three of the background cases that we model. Peak demand increases from 63.8GW in 2030 to 100.8GW in 2050.

Figure 7 Peak and Total Demand



Source: LCP Delta

Note: These are the demand assumptions used in all of the scenarios from 2030-2050. Daily demand shapes are based off historical demand patterns

5.4 Modelling results

In the following section we describe the key results from the modelling of the counterfactual and factual scenarios. We structure our results as follows:

- First, for context we present some key system results, including the level of congestion on the key B2 and B6 boundaries;
- Second, we describe the operation of storage plants in the counterfactual scenarios, in particular examining the correlation of storage charging with periods of constraints. This analysis is aimed at demonstrating the value that storage can bring to relieving constraints;
- Third, we consider the implications for system costs of adding more storage (assumed to be partially incentivised as a result of CMP405), and show that additional storage reduces the operational costs (i.e. fuel, carbon and VOM) of running the electricity system, in particular due to the fact that otherwise wasted wind energy is utilised reducing the need for other higher cost generation; and
- Finally, we consider the implications for consumer costs of adding more storage, including the changes to wholesale costs, policy costs and constraint costs.

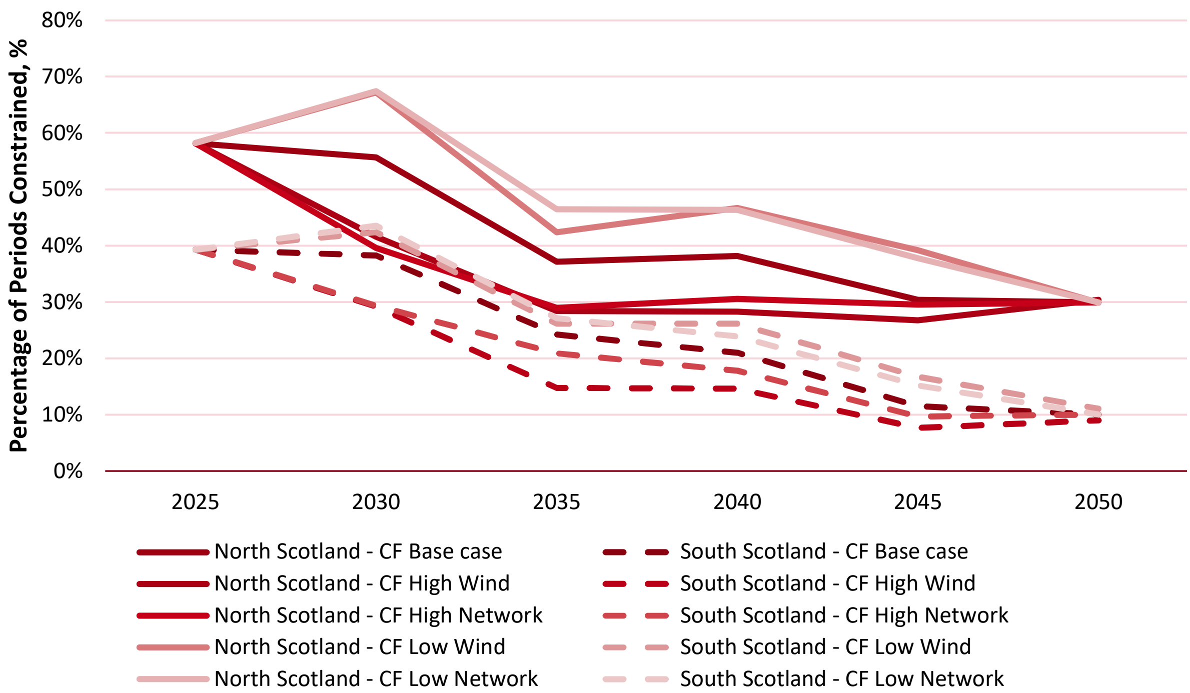
5.4.1 Wider system results (Counterfactual scenarios)

Boundary Constraints

The B2 boundary is constrained during between 10% (in High Network) and 24% (in Low Network) of periods in 2035, rising thereafter to approximately 26% across all scenarios by 2050. The proportion of time that B6 boundary is constrained falls gradually over time, from around 30-40% in 2030 to approximately 10% in 2045. North Scotland is generally more constrained than South Scotland, as it is behind both the B2 and B6 boundaries, while South Scotland is only behind the B6. North Scotland.

As expected, the boundaries are less constrained under the High Network Build case compared to the Base Case, with the higher network capacity allowing more energy to be exported South. The boundaries are also generally less constrained under the High Wind case compared to the Base Case. Though we would expect higher wind to lead to more constrained periods, like the Base Case, the network build has been optimised to accommodate a higher level of wind capacity in the High Wind case. In addition, the higher offshore wind build is assumed to primarily connect south of the B6 boundary. This means that excess wind drives low prices at a national level rather than just in Scotland. The zero national wholesale prices mean Scottish wind generates less in the wholesale market (effectively self-curtailing when national prices are zero), relieving constraints on the B2 and B6 boundaries.

Figure 8 Proportion of time North Scotland (B2 or B6 boundary) and South Scotland (B6 boundary) are constrained



Source: LCP Delta

Note: When considered in the locational run, this represents the amount of time the boundary is at full capacity

Additional graphs on the length, depth and frequency of these constraints can be found in Annex C.

5.4.2 Behaviour of storage during constrained and zero priced periods

The behaviour of storage during periods of constraints is of particular relevance to the case for CMP405. The charts below show the charging load factors of marginal (i.e. 1MW) storage units of different durations, for 1 hour, 8 hours and 23 hours during constrained periods. Marginal storage units are of 1MW capacity and always bid at the price of the marginal generation asset.

Equivalent load factor results during constrained periods can be found in the Annex B.

These load factor results have been calculated using the counterfactual scenario for each of the five background sensitivities. The main line shows the Base Case results while the pink area represents the range across the sensitivities.

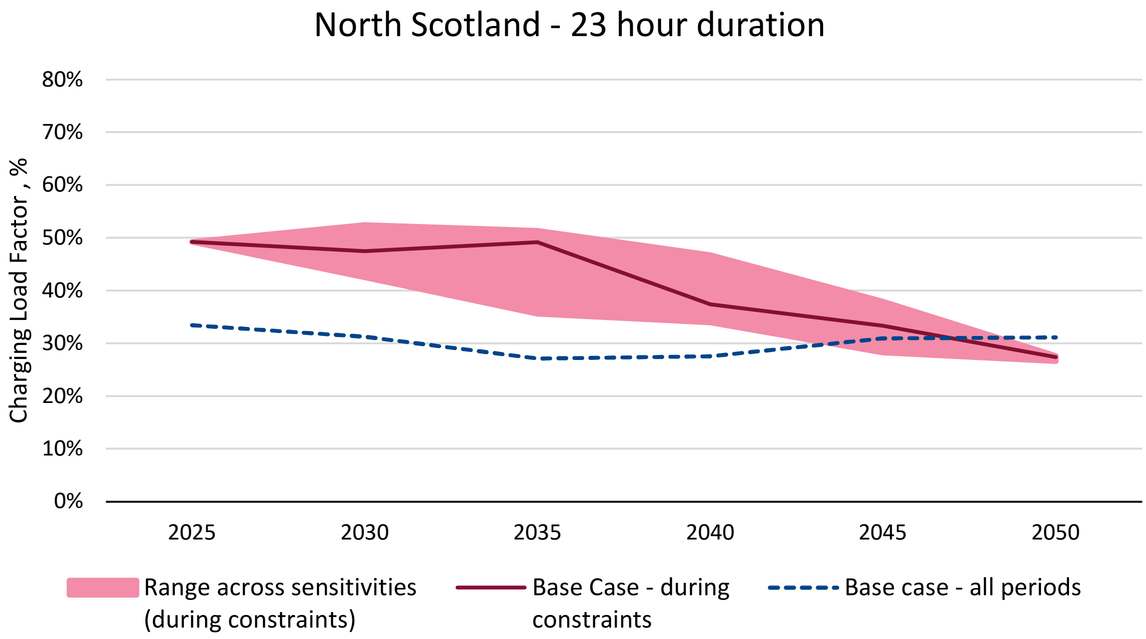
Charging load factors

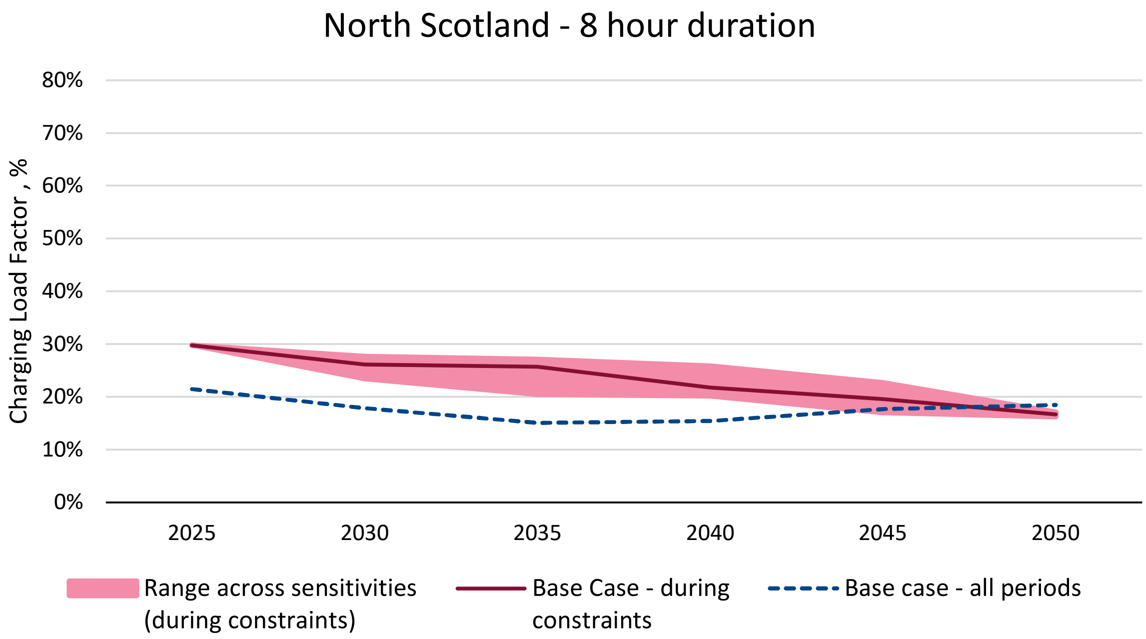
In North Scotland when the B2 or B6 boundaries are constrained, longer duration storage is much more likely to be charging to help relieve constraints than shorter duration assets, with a 23-hour storage unit charging during 47% of constrained periods in 2035 compared with a 1-hour unit charging during only 4% of constrained periods in the Base Case.[32] This is largely due to the length of constrained periods which will often last for a period of consecutive hours beyond the duration of battery storage assets.

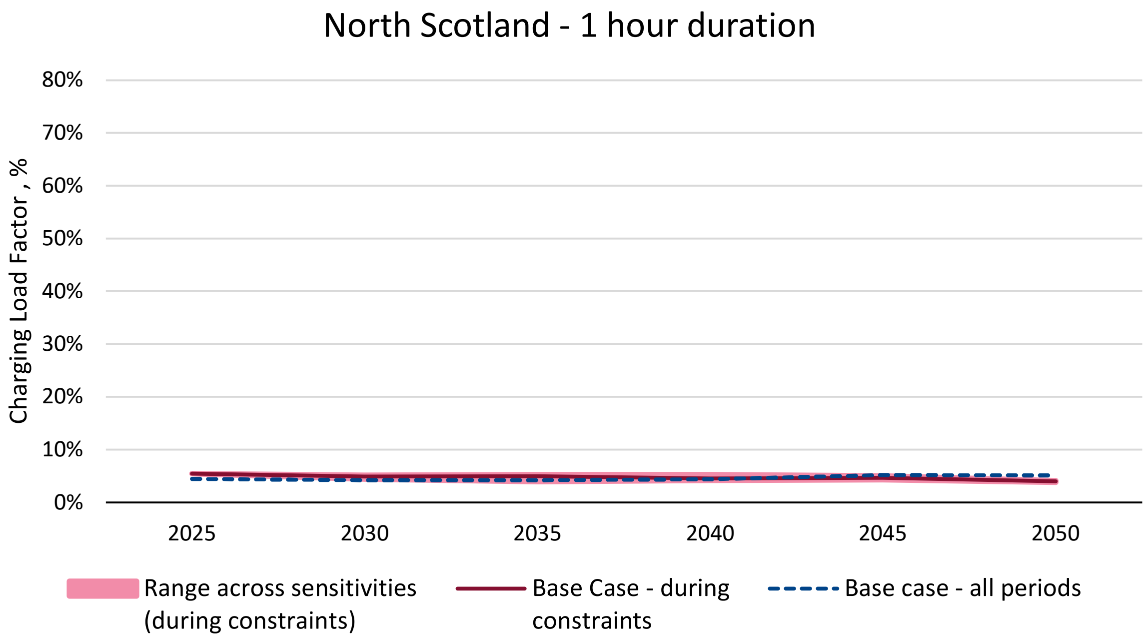
Storage load factors during constrained periods are generally highest in 2025 where there is a high proportion of constrained periods, and fewer zero wholesale prices outside of constrained periods. Therefore, storage plants are more likely to be able charge in more of these periods.

[32] The load factor results are sensitive to the priority order assumed for wind curtailment during national zero price periods. As a result, the results presented are an average of two scenarios, one where Scottish wind is curtailed before English & Welsh wind, and one where it is curtailed after.

Figure 9 Charging load factor during constrained periods for different storage durations – North Scotland, (Counterfactual)



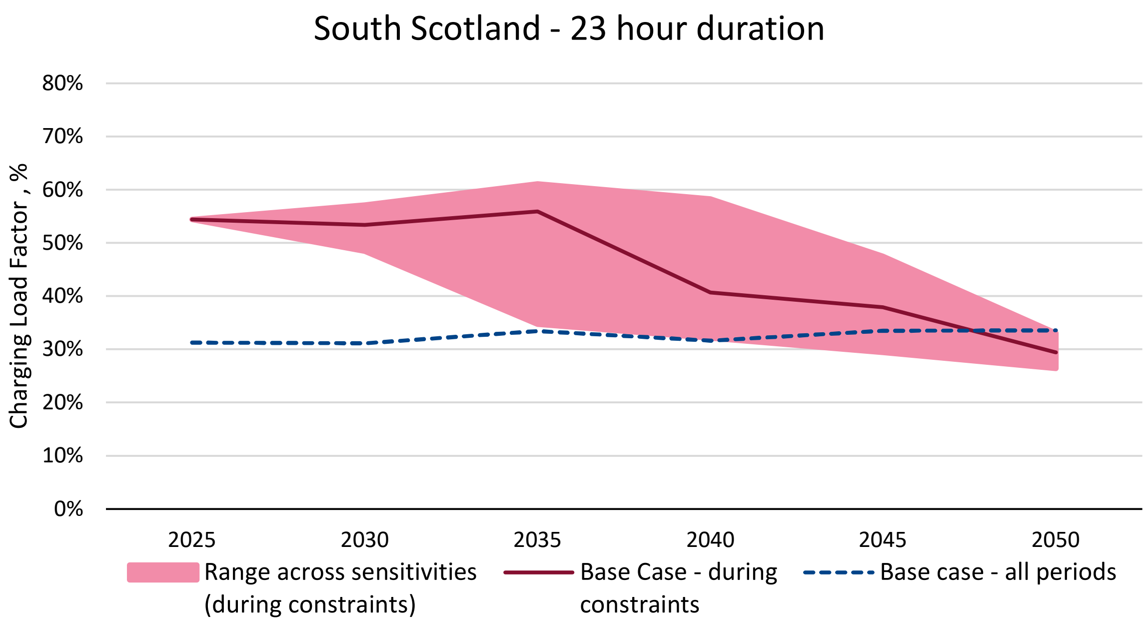


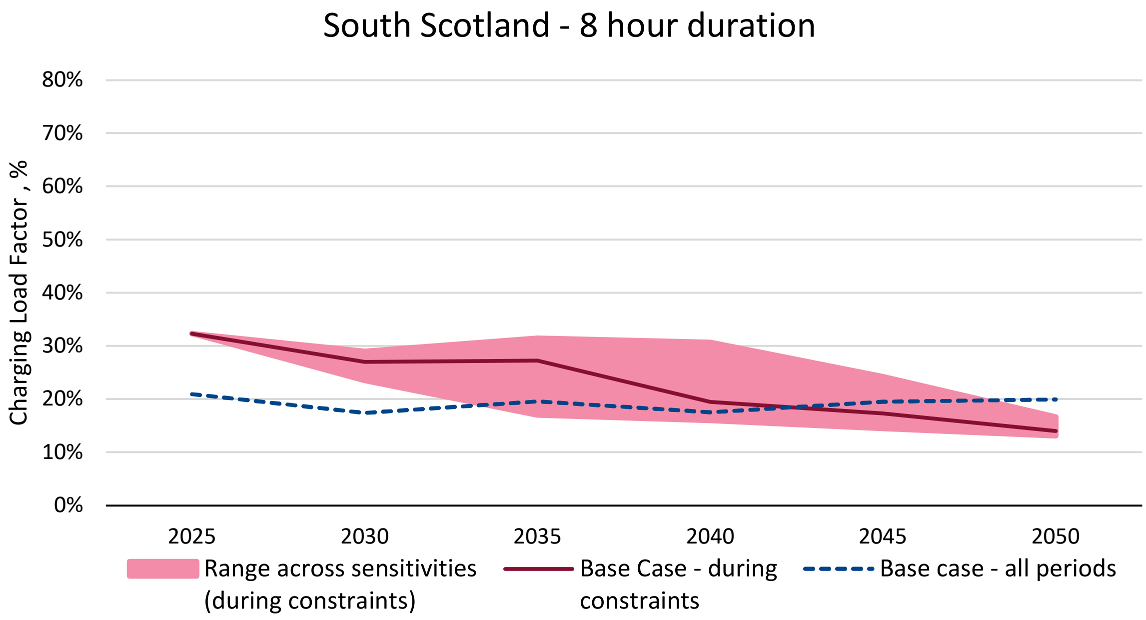


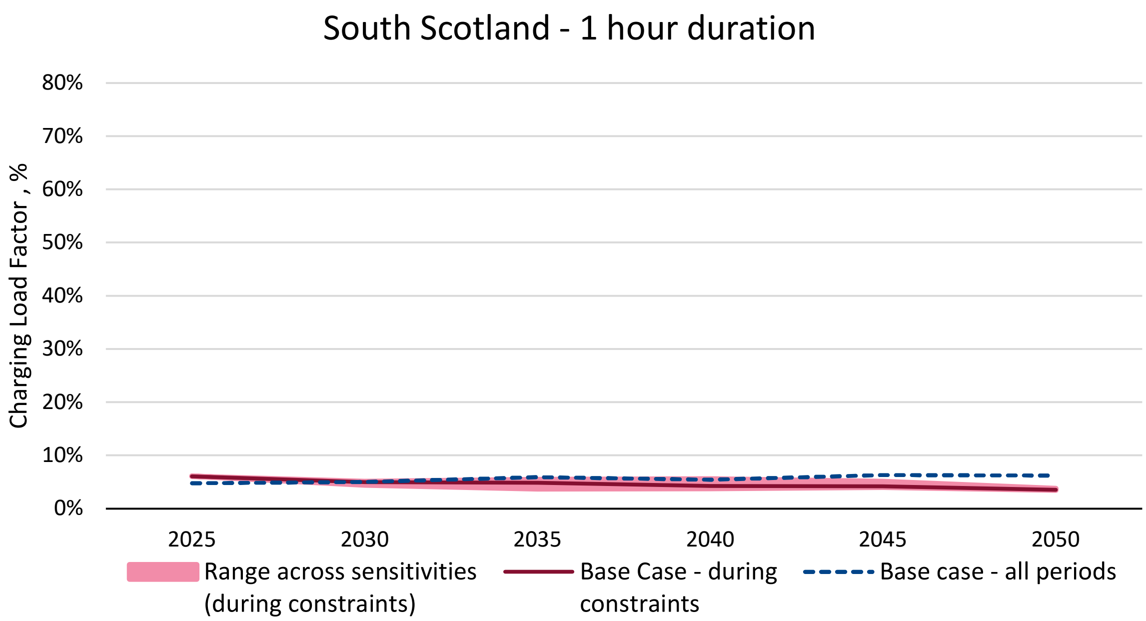
Source: LCP Delta
Note: The charts show the load factor of different duration assets during constraints periods and then during all periods.

The load factors of similar duration units are slightly higher in South Scotland than in North Scotland. This is likely to be due to shorter durations of constrained periods, which are driven by constraints on just the B6 boundary (rather than B2 or B6).

Figure 10 Charging load factor during constrained periods for different storage durations – South Scotland (Counterfactual)







Source: LCP Delta

Note: The charts show the load factor of different duration assets during constraints and then during all periods.

Charging load factors – High Wind case

Charging load factors during constrained periods in the High Wind case are lower than in the Base Case. More wind causes more low-price periods. Therefore, storage will charge less due to the fact there are not enough periods where it can profitably discharge. In addition, storage has more opportunities to charge outside of constrained periods, when there is an oversupply of wind at a national level and prices are zero.

Charging load factors – High Network Build case

In comparison to the Base Case, storage assets in the high network build sensitivity charge slightly less during constrained periods.

Charging load factors – Low Wind case

Charging load factors during constrained periods in the Low Wind sensitivity are higher than in the Base Case (for example 61% for 48 hour duration in 2035 rather than 58%). The lower levels of wind in this sensitivity result in fewer zero prices (either in the wholesale market or due to locational constraints) for shorter number of consecutive periods. These periods of higher (non-zero) prices provide opportunities for the storage to discharge, which allows the storage to charge during constrained periods.

Charging load factors – Low Network Build case

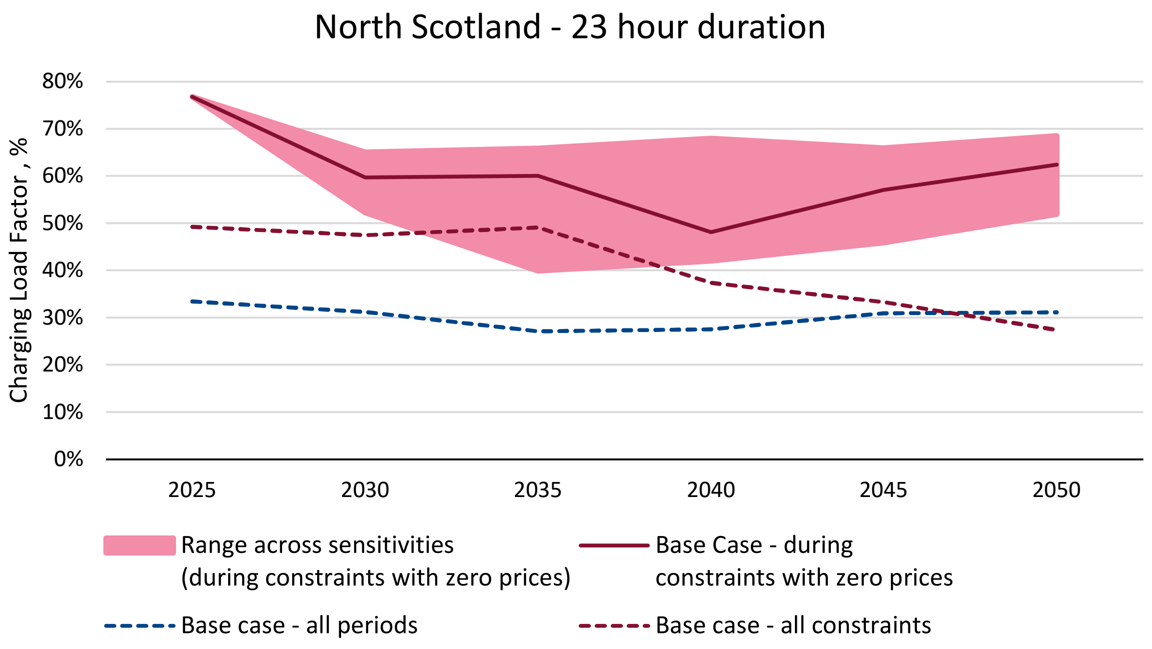
In comparison to the Base Case, storage assets in the low network build sensitivity charge slightly less during constrained periods. This is because constrained periods are more frequent and for longer consecutive periods, meaning storage is less likely to be able to charge throughout constrained periods.

Charging Load factors during constraints with zero price periods

Periods with zero locational prices behind constraints are likely to represent the costliest periods for congestion management for both the system and consumer. These typically occur where wind is curtailed. Constraints in other periods can be eased by turning conventional plant down or turning electrolysers up to increase demand.[33]

Storage is more likely to charge during zero price constrained periods, acting to prevent wind curtailment and reduce congestion management costs. For example, in North Scotland, 23 hour storage charging load factors during zero price constraint periods is around 60% in 2030 and 2035, compared to around 50% for all constrained periods.

[33] Conventional plants may be willing to pay to be curtailed, reflecting their positive short run marginal cost. Similarly, electrolysers may be willing to bid positive prices in the BM to increase their demand.



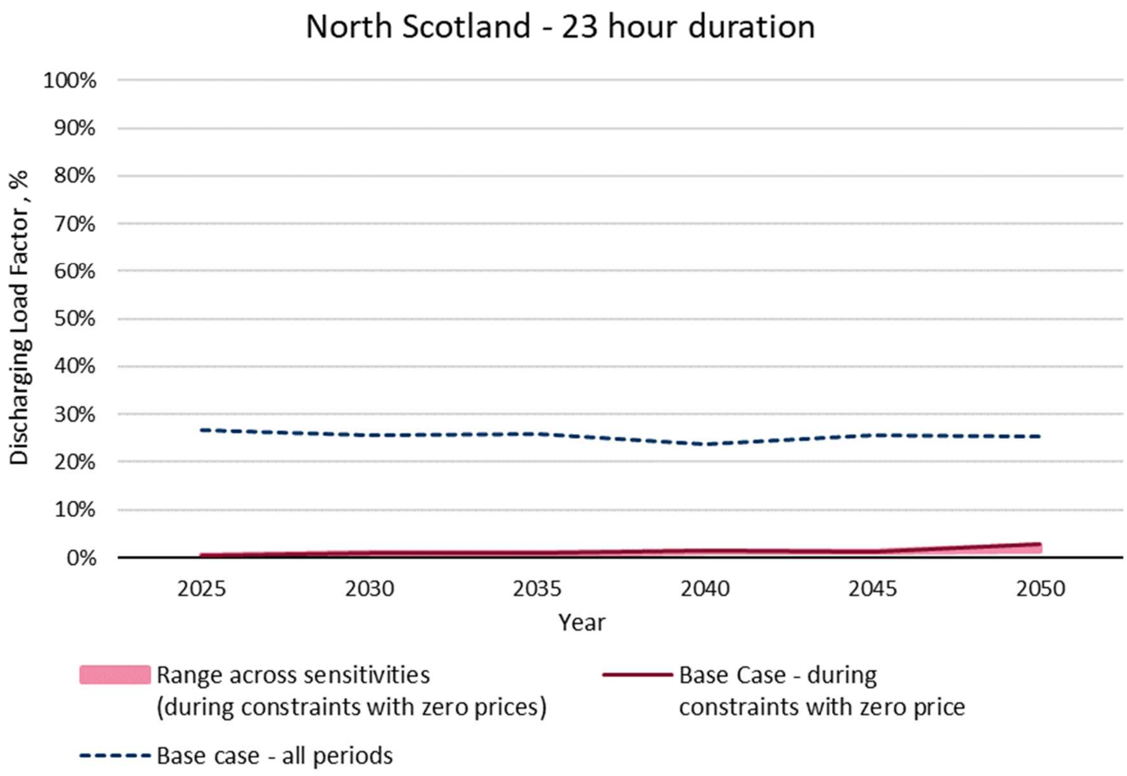
Further results for storage load factors during constrained periods (for all periods and periods with zero prices) can be found in the Annex D.

Discharging load factors

The modelling results show that storage located in Scotland discharges much less frequently during periods of constraint than it charges. This is because storage is incentivised through either the wholesale market or through balancing actions to help relieve the constraint rather than exacerbate it.

When it does discharge during constrained periods, these are rare periods and are often a result of storage discharging to supply electrolysers (using charge from periods of excess wind generation), where locational constraint prices are greater than zero. This behaviour is desirable for the system, making more efficient use of electrolyser capacity. Its discharging load factor when prices are zero or below (i.e. wind is being curtailed) are very low, as shown on the chart below.

Figure 11 Discharging load factor during constraint periods with zero prices – North Scotland (Counterfactual)



Source: LCP Delta

Note: The charts show the load factor of different duration assets during constraints and then during all periods.

Other durations and South Scotland storage sees similarly low levels of discharge during constraints to North Scotland.

5.4.3 Factual Scenario Results Compared to Counterfactual

In this section we show that additional storage located in Scotland would deliver an operational system cost saving relative to the counterfactual in each of the background scenarios. We also show that the savings are greater for LDES (FS1) than for storage with shorter durations (FS2) where the equivalent capacity, not storage volume, is deployed. CMP405 wouldn't necessarily incentivise all the storage in FS1 or FS2; our modelling only shows that these scenarios would offer an operational system benefit in relation to the counterfactual.

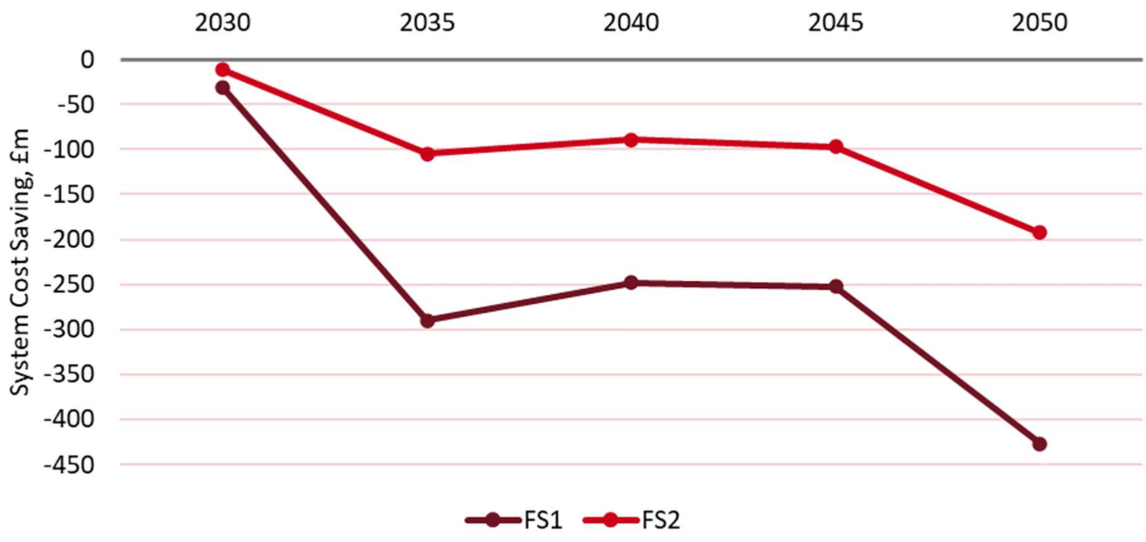
FS1 includes longer duration storage, in line with the pumped storage capacity assumed under NGESO's Leading the way scenario in the longer term. FS2 includes the same capacity (in GW terms) of shorter duration storage, split evenly between 2, 4 and 8 hour capacity. For more detail, please see the Modelling Assumptions section.

As noted earlier, this analysis is not a full assessment of system costs as we are not assessing any changes in overall capex of the system that might arise to additional storage capacity. The benefits that we are assessing relate to the operational costs of running the electricity system.

Operational System Benefits – Base Case

The graph below shows the system cost saving in the FS1 and FS2 scenarios when compared to the counterfactual. The savings are between £250m to £430m per year between 2035 and 2050, for the LDES cohort in FS1, whereas the same capacity of shorter duration storage in FS2 provides around £90m to £190m of benefit per year. These system benefits reflect the fact that storage pumps during periods of constraint allowing wind generation that would otherwise be wasted to be utilised in another period.

Figure 12 System cost saving in the Base Case , Factual scenarios vs Counterfactual (real 2022 terms)

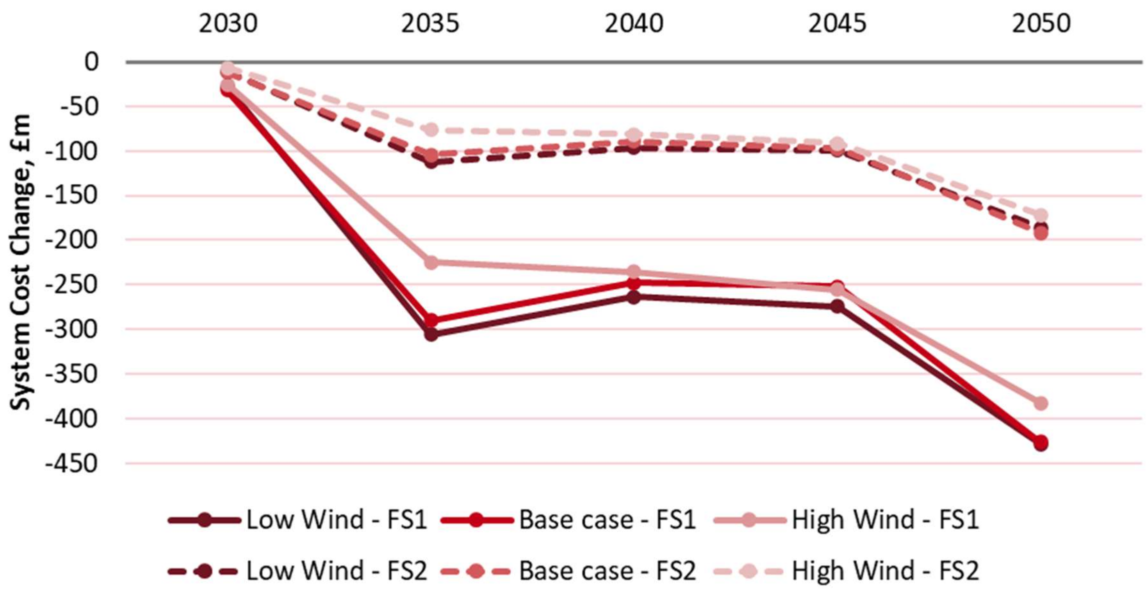


Source: LCP Delta

Operational System Benefit – High and Low Wind cases

Under both the High and Low Wind cases, FS1 results in lower system costs than the counterfactual and a larger system cost saving than FS2. The High Wind case shows a smaller cost saving than the Base Case, especially in 2035, when the High Wind case differs most from the Base Case, with 30GW more offshore wind capacity. The Low Wind case has a marginally higher system cost saving than the Base Case.

Figure 13 System cost saving in the High & Low Wind case, Factual scenarios vs Counterfactual (real 2022 terms)



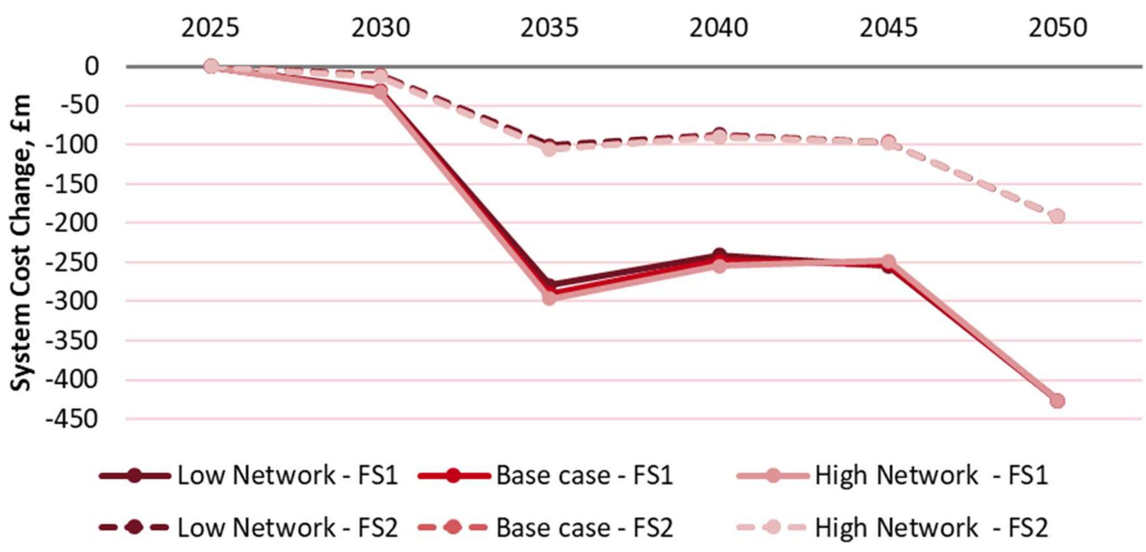
Source: LCP Delta

With higher wind build out, the system benefits of FS1 and FS2 are lower, particularly in 2035, but still significant. With lower wind build out, the system benefit is higher. This illustrates that in a system with a greater degree of wind generation, there are fewer periods where high cost generation on the system can be displaced by storage discharging.

Operational System Benefit – High and Low Network Build cases

In the High Network Build case, the system benefit of FS1 and FS2 is slightly higher, particularly in 2035 but lower by the time we get to 2050. In the Low Network Build case, the system benefit of FS1 and FS2 is marginally lower. This is due to the fact that in a system that is less saturated with wind generation, costs are higher as other, more expensive technologies, are generating. Storage assets can act to reduce these costs.

Figure 14 System cost saving in the High & Low Network Build cases, Factual scenarios vs Counterfactual (real 2022 terms)

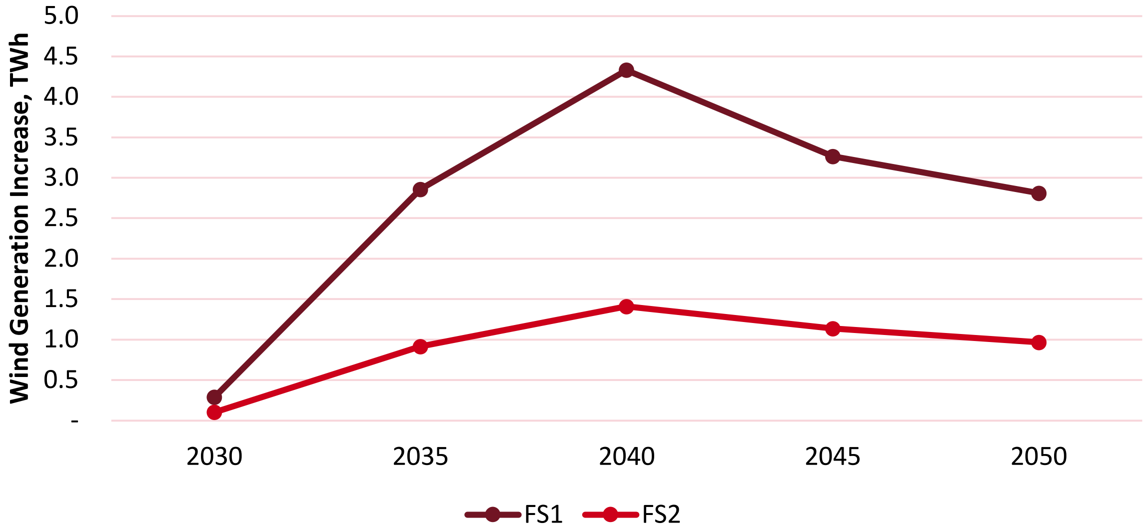


Source: LCP Delta

Wind Generation – Base Case

Wind output increases between the counterfactual and factual scenarios, due to LDES enabling more of the surplus wind generation to be utilised, reducing curtailment. FS1 and FS2 see a lot more wind generation than the counterfactual. In 2040, there is 4.3TWh more wind generation in the FS1 scenario. Long duration storage in Scotland is primarily charged using wind generation and displaces more expensive types of generation on discharge.

Figure 15 Excess wind generation utilised, Factual scenarios vs Counterfactual – Base Case

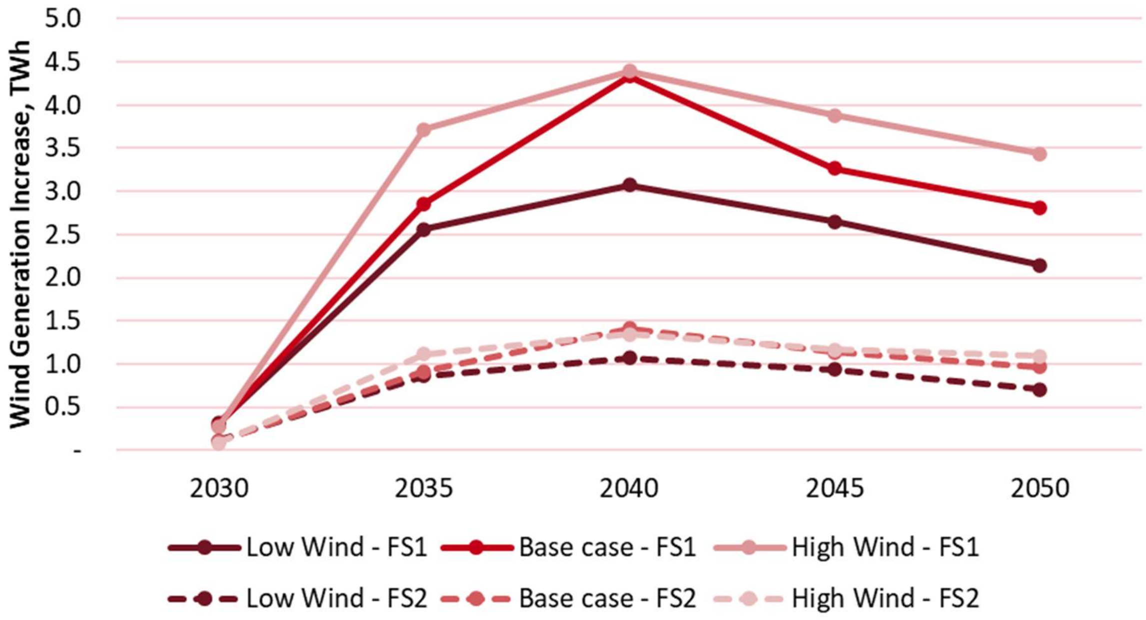


Source: LCP Delta

Wind Generation – High & Low Wind cases

Under the high wind sensitivity, there is more surplus wind for storage to utilise, particularly in 2035, with the LDES in FS1 utilising around 3.7TWh of surplus wind generation in 2035 compared to 2.9TWh in the Base Case.

Figure 16 Excess wind generation utilised, Factual scenarios vs Counterfactual – High & Low Wind cases

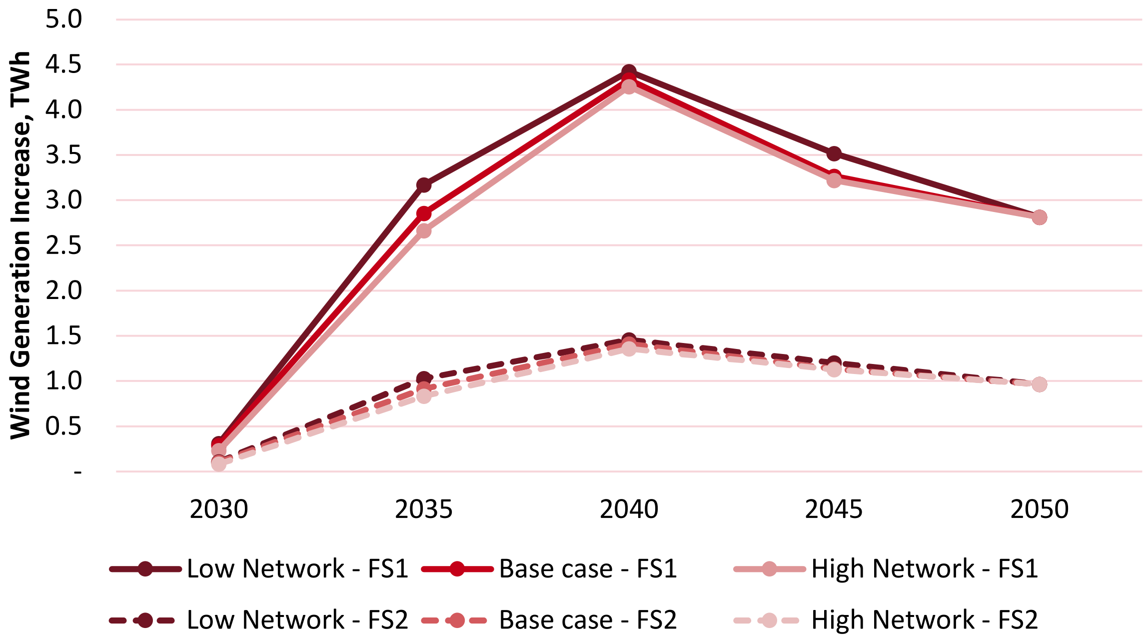


Source: LCP Delta

Wind Generation – High & Low Network Build cases

With higher network build, slightly less surplus wind is utilised in the factual scenarios relative to the Base Case, but the overall impact is minimal, demonstrating that the benefits of storage are robust to “over investment” in the network.

Figure 17 Excess wind generation utilised, Factual scenarios vs Counterfactual – High & Low Network Build cases



Source: LCP Delta

Consumer cost impact

The consumer cost is comprised of the wholesale cost, policy costs (from CfD and ROC payments) and constraint costs. Network costs and other costs are not modelled here. We have assumed that CfD support levels would change in line with changing renewable profits. The remaining costs are split out for the Base Case.

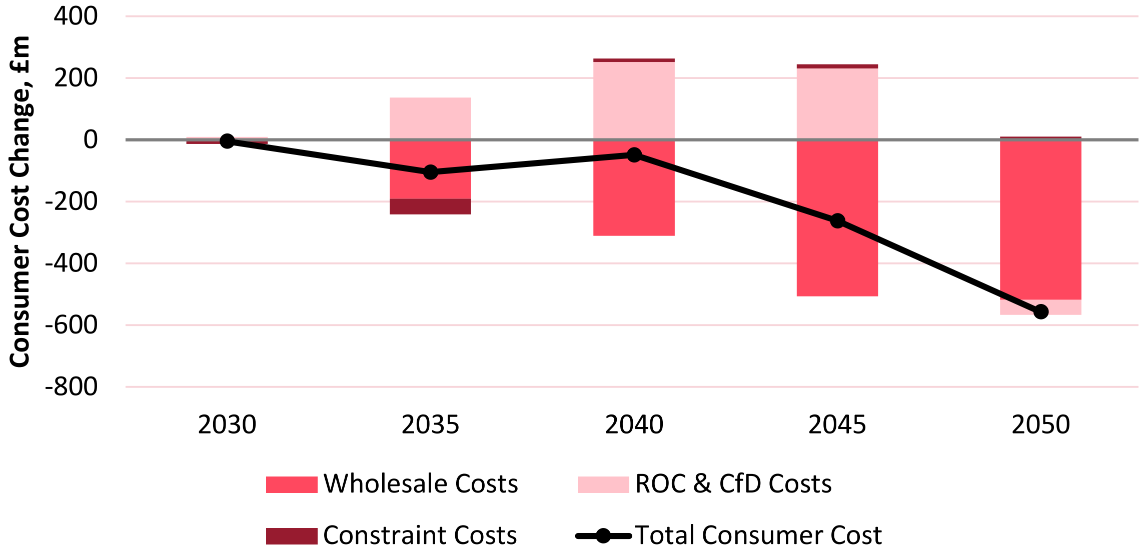
In the modelling of plant bidding during constraints, we have assumed that plant bid at break-even, rather than bidding to make a profit. The sensitivity of overall consumer cost results is small. See Annex A for more detail, including the sensitivity of consumer cost results to this assumption.

Consumer Cost – Base Case

The additional storage saves consumer costs in all years except 2040. Wholesale costs are reduced significantly, but policy costs (ROC and CfD costs) increase as there is additional wind generation. Constraint costs are saved in 2030 and 2035 but increase (under FS1) from

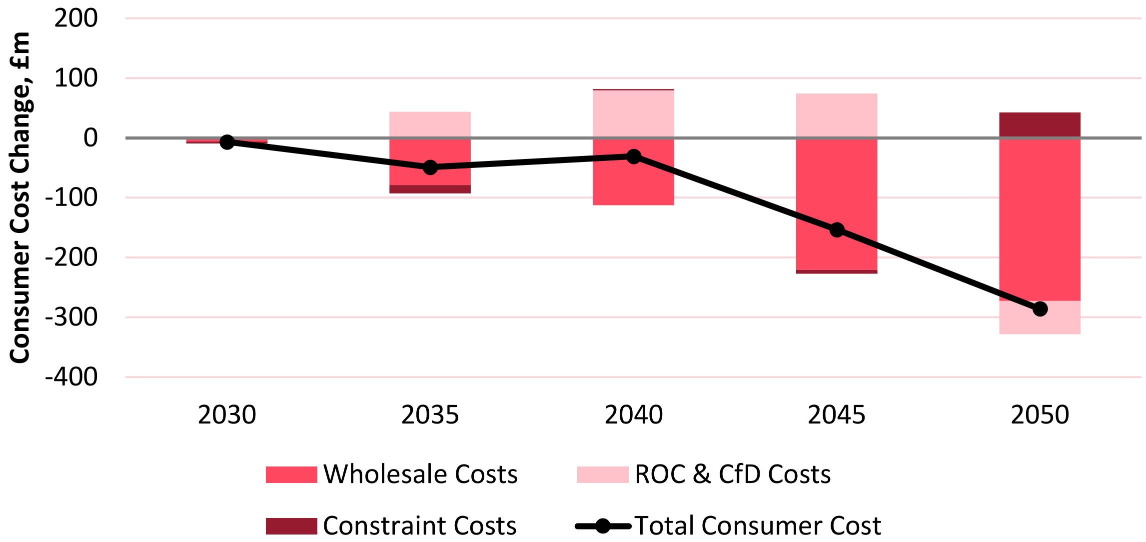
2040 onwards. One reason for this change in later years is there are lower savings from preventing negative wind bids, as wind support contracts end.

Figure 18 Consumer cost change, FS1 vs Counterfactual – Base Case (assuming plant bid at cost for locational constraints), real 2022 terms



Source: LCP Delta

Figure 19 Consumer cost change, FS2 vs Counterfactual – Base Case (assuming plant bid at cost for locational constraints), real 2022 terms

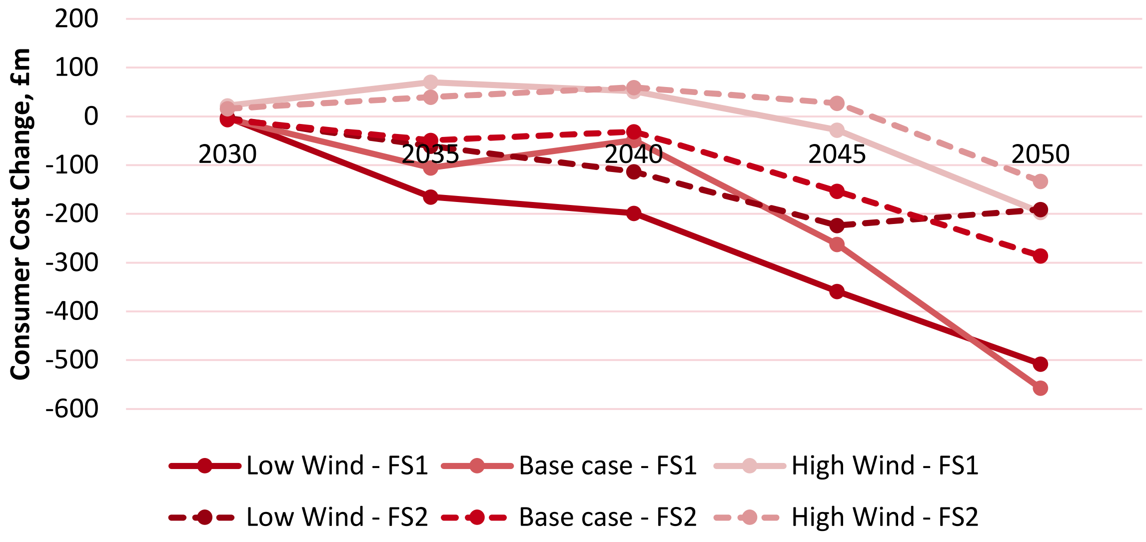


Source: LCP Delta

Consumer cost change – High and Low Wind cases

Consumer costs increase in most years with the addition of storage under the High Wind case but decrease in all years under the Low Wind case. In the High Wind case, wholesale costs are already low, limiting the benefits from storage. In addition, storage acts to prevent greater amounts of wind curtailment in the High Wind case (both in national and locational balancing), which results in higher policy costs.

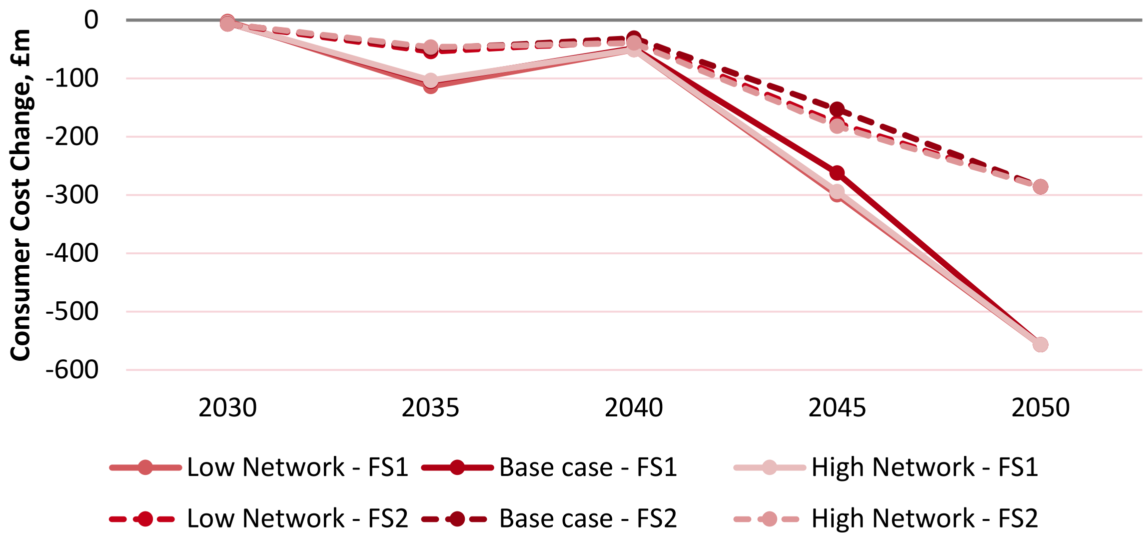
Figure 20 Consumer cost change, Factual scenarios vs Counterfactual – High and Low Wind (assuming plant bid at cost for locational constraints), real 2022 terms



Source: LCP Delta

Consumer cost change – High and Low Network Build cases

Figure 21 Consumer cost change, Factual scenarios vs Counterfactual – High and Low Network Build (assuming plant bid at cost for locational constraints), real 2022 terms)



Source: LCP Delta

5.4.4 Modelling Limitations

The modelling presented in this report can help to inform the nature, direction and broad magnitude of potential effects of the modifications being considered. However, the modelling outputs we present are dependent on assumptions on a number of inherently uncertain input variables (e.g., fuel prices, demand). Such outputs are best used to complement a more principles-based assessment of the likelihood of modifications better facilitating objectives.

There are a number of specific limitations to the modelling which we note below. However, we do not expect them to have a significant impact on the quantitative results.

- Storage behaviour is optimised alongside other generation assets to minimise the total system dispatch costs. Storage assets do not specifically act to maximise their profits, although this usually results in the same actions.
- Plant dispatch is optimised within day in the modelling. The only exception to this is for the long duration plants which are 'pre-optimised' over a longer time period to determine their state of charge at the end of each day.
- Hydrogen electrolysers are assumed to be fully flexible in their response to both wholesale prices and for balancing locational constraints, which may not be feasible in reality.
- Demand Side Response (DSR) is not explicitly modelled (but is included within the fixed demand profiles).

- Reserve, response, voltage, or inertia constraints as well as balancing for national energy imbalance reasons within the balancing mechanism are not modelled.
- Demand and Intermittency (weather) inputs are based on historical profiles.
- Each interconnected country outside of GB is modelled as one zone with generation and prices in these countries modelled in the same way as domestic zones.

5.4.5 Conclusion from modelling

The modelling results support the case for providing a cost reflective incentive to storage, and there is a case that this incentive, if based on maximum import load, should be larger for longer duration storage relative to shorter duration. Factual scenario 1 (FS1), delivered a significant system cost saving relative to the counterfactual. Furthermore, the system cost saving under FS1 is greater than the saving under FS2, demonstrating the additional value that LDES provides, over and above an equivalent MW capacity of SDES.

6 Demand credit design options

The CMP405 proposal does not specify a detailed design for the proposed demand credit and is explicit that it anticipates the demand credit design "*changing following workgroup discussions*".[34] In this context, SSE has asked us to qualitatively consider what features would be appropriate for the design of the CMP405 demand credit. The key messages for this section are set out below.

Key messages – Section 6

- The demand credit should be designed to avoid dispatch distortions and should reflect the extent to which the relevant asset contributes to the relief of transmission constraints.
- A capacity-based charge would leave storage with incentives to resolve network constraints efficiently, and therefore should be preferred to a volumetric based charge.
- Precedent from the existing TNUoS charging methodology for intermittent generation would suggest a capacity-based charge calculated by scaling the zonal Year Round charge element by the storage unit's expected demand during constrained periods (i.e. its 'Constrained ALF').
- A 'Constrained ALF' approach to the design of the demand credit could lead to different levels of credit for different storage technologies, or specific plants, depending on their expected contribution to the relief of network constraints.

For the design of the CMP405 demand credit to result in efficient outcomes we consider that it should reflect two key principles.

- *First*, the demand credit should not distort otherwise efficient dispatch incentives; and
- *Second*, the size of the demand credit should reflect the extent to which the relevant asset contributes to the relief of constraints (which would otherwise drive the need for additional investment in the transmission system). When considering this principle, it will also be important to bear in mind relevant precedent derived from the treatment of other technologies within the existing charging framework.

We expand below on what each of these principles implies for the appropriate design of a CMP405 demand credit before summarising what design features would be appropriate given these principles.

34 https://www.nationalgrideso.com/document/271461/download

6.1 The demand credit should avoid creating dispatch distortions

A combination of wholesale market prices and ESO balancing mechanism actions should, in theory, result in efficient short term dispatch patterns for all generating and flexible demand assets. This means that any change to flexible demand or generation dispatch incentives arising from the implementation of CMP405 would not be capable of improving the short term dispatch of the electricity system. Rather, by altering dispatch incentives, the demand credit could only be capable of reducing the efficiency of short term dispatch. Indeed, the current "floored at zero" regime was motivated by the concern that a negative locational demand charge might create a distortion in the form of increased demand at times of tight margins/peak demand, thereby emphasising the importance of this criteria.

In broad terms, there is a choice between volumetric or capacity based charges.[35] A volumetric charge, based annual consumption, recognises the value that storage brings to relieving constraints in off-peak periods throughout the year. However, any volume based charge typically distorts dispatch incentives by changing the payoff that market participants face when making their dispatch decisions.

In contrast, capacity-based charges typically do not distort dispatch incentives because the size of the credit does not change based on individual dispatch decisions by the storage operator. Therefore, there is a clear case for considering capacity based charges, which is consistent with the current approach to generator TNUoS charges. Generators face capacity-based TNUoS charges as described in Figure 22 below, which are based on the generator's maximum capacity (TEC), average load factor (ALF),[36] and sharing factors. Adopting a similar approach for CMP405 would minimise the risk that transmission-connected electricity storage assets would alter their otherwise efficient operational decisions in an attempt to increase the amount of the credit they receive.

6.2 The size of the demand credit should reflect the extent to which storage assets enable transmission investment to be avoided

For the CMP405 demand credit to provide an efficient investment signal, the size of the demand credit should reflect the cost of network investment that is efficiently avoided by the installation of storage assets in negative locational demand charging zones. We consider the implications of this principle in two stages:

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35 In principle, there are many possible variations of how charges could be levied. e.g. Ofgem's TCR introduced fixed per site charges based on volumetric and capacity bands for the collection of residual charges. However, fixed per site charges are used to collect collection of residual charges and are less relevant and appropriate for cost reflective charges.

36 We note that ALFs are set on an ex ante basis, and are updated slowly, reflecting 5 years of rolling data. Thus, the possible distortion to dispatch incentives arising from partially basing charges on observed behaviours is minimised.

- First, we identify the element of TNUoS charges that relates to the network investment that appropriately located storage assets can avoid; and
- Second, we consider how the identified element of charges should be applied in the final credit for storage, recognising the contribution of storage assets to avoiding network investment.

6.2.1 Relevant TNUoS element

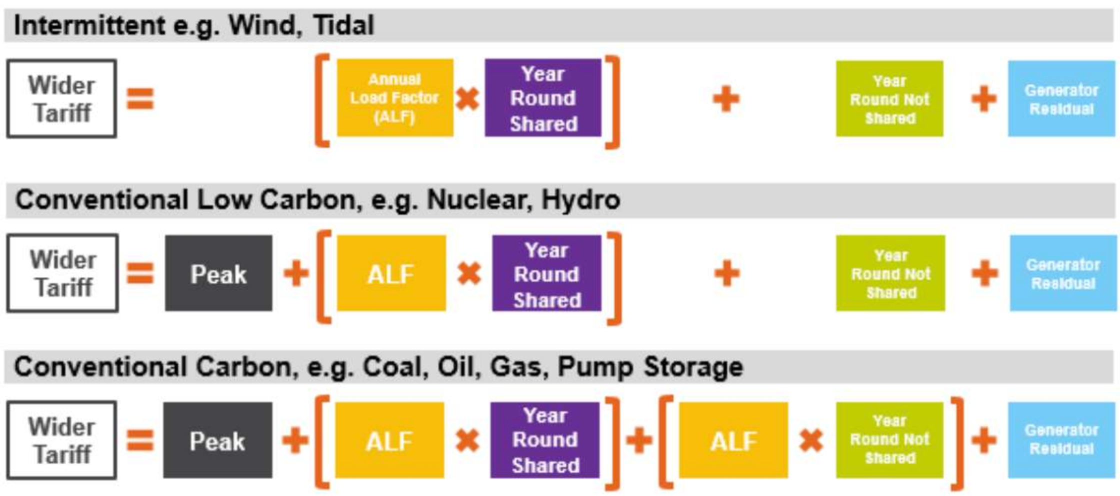
Demand charges have two components, a Peak Security component and a Year Round component. The case for a CMP405 demand credit is based on the principle that storage assets in negative demand charge zones can reduce network congestion outside of times of peak demand when local transmission circuits would otherwise be congested. Therefore, the demand credit should be linked to the size of the Year Round element of the demand TNUoS charge only. This would leave the Peak Security element of the demand TNUoS charge unaffected by CMP405.[37]

6.2.2 Application of the relevant TNUoS element

As noted above, when considering the specific case of storage, it is important to bear in mind the precedent set by the treatment of other technologies in the existing charging framework.

For generation TNUoS charges, Year Round charges are payable by generators based on their capacity (TEC), their ALF and sharing factors as illustrated in Figure 22 below.

Figure 22 Calculation of TNUoS Generation Tariffs



Source: https://www.nationalgrideso.com/document/130271/download

[37] In practice storage operators are unlikely to actually pay the Peak Security element of demand TNUoS charges because they are highly unlikely to be charging during Triad. This is the case either with or without CMP405.

The current charging methodology offers two possible precedents for the calculation of a demand credit:

- First, the treatment of conventional carbon generation; and
- Second, the treatment of intermittent generation.

Precedent from existing treatment of conventional carbon generation

Conventional generation assets (including pumped storage) pay a Year Round charge based on their TEC*ALF. This reflects the idea that generation from conventional sources, outside of Triad periods, is not correlated – either positively or negatively – with periods of transmission constraints. Therefore, on average expected generation from conventional assets during periods of network constraints is assumed to be TEC*ALF and charges are set on this basis.

A close analogy for the treatment of storage in a negative *demand* charging zone is the treatment of generation in a negative *generation* charging zone, which receives a TNUoS credit, based on its TEC*ALF.[38] In the case of the generation located in a southern zone, it may be regularly generating during periods of constraint (including when called to generate by the ESO to relieve a constraint).

It could be argued that as a source of demand in a negative locational demand charging zone, storage has a similar impact on network constraints as generation in negative generation zones, and therefore storage's treatment in the charging methodology should be similar i.e. a Year Round credit based on its capacity adjusted by its ALF.

Precedent from existing treatment of intermittent generation

There is also precedent for making adjustments to the charges that different plant pay to better reflect the correlation of a specific technology's output with constraints.

The charge that intermittent generators pay reflects the same basic principle[39] as charges for conventional carbon generation but includes an additional parameter, a sharing factor, to better reflect the correlation of intermittent output with local constraints. The sharing factor depends on the prevalence of low carbon generation upstream of a boundary.[40]

38 We note that ALF is calculated based on the maximum of Final Physical Notification (FPN) or metered output.

39 The principle of charges being intended to reflect the probability that different plants are drivers of network constraints.

40 Boundary sharing factors are calculated for the boundaries between each charging zone based on the capacity within zones that export power across each boundary. This reflects a proxy for whether intermittent generation upstream of the boundary is a driver of constraints on that boundary. However, intermittent generation ultimately pays TNUoS charges reflecting boundary sharing factors on all zone boundaries along its notional path to demand.

- If all generation upstream of a boundary is “low carbon”[41] then intermittent generation is expected to be a driver of periods of constraints[42] and thus intermittent generation is assumed to be strongly correlated with constraint periods. In this case, intermittent generators face a charge based on their TEC.

- Alternatively, if “low carbon” generation represents only a minority of generation upstream of a boundary, then its output is not expected to be a driver of periods of constraints and thus intermittent generation is assumed to be uncorrelated with constraint periods. In this case, intermittent generators face a charge based on their TEC*ALF.

Given this approach for intermittent generation, it could be appropriate to scale the Year Round credit receivable by storage in a zone to its expected demand during constraint periods. Under such an approach, assets could receive a zero Year Round credit, a partial Year Round credit, or a full Year Round credit depending on their expected charging during periods of constraints.

- If a storage asset is always expected to be charging at full capacity during periods of local constraints, then its expected demand during those periods should reflect its maximum import limit (MIL),[43] and as a result, a storage asset could receive a demand credit based on its MIL with no ALF based adjustment. This is analogous to an intermittent generator operating in a wholly low carbon generation zone paying Year Round charges based on its TEC, with no ALF adjustment because it is always expected to be generating when there is a transmission constraint.

- If a storage asset is not expected to be charging during periods of local constraints, and hence not helping to relieve that constraint, then it would receive zero credit.

- If a storage asset charges only in some periods of constraint or at less than its full capacity, its charge should be set based on its MIL multiplied by its load factor during periods of constraints i.e. a ‘constrained ALF’.

This approach introduces the new parameter of a ‘constrained ALF’, which could be set ex ante in the same way as ALF is currently, in order to avoid distortions to dispatch.[44] The idea

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41 This definition of low carbon excludes dispatchable plant with a positive short run marginal cost, such as biomass.

42 When the wind blows, intermittent output is high, and this is when constraints are most likely.

43 Defined as the maximum level at which the BM Unit may be importing (in MW) from the GB Transmission System.

44 We note that there are two practical challenges with this “constrained ALF” approach. The first practical challenge is that initially there will not be actually observed data on which to base a “constrained ALF”. Therefore, it may be initially necessary to derive estimates of likely constrained ALFs from modelling in order to set the initial demand credit size. The second practical challenge is that TNUoS charges are conceptually intended to be set on the basis of optimised network build. However, actual levels of network build may deviate from this and affect the storage units “constrained ALF”. This is a more general issue that also affects the ALFs of peakers in negative generation charge zones under the current methodology. Therefore, this is a limitation that may have to be accepted. An alternative approach would be to seek to continue to model a constrained ALF assuming a reoptimized level of network build even once data on the actual constrained ALF is available. Such an approach, of modelling a ‘derating factor’ when actual data is available would not be entirely novel, as such an approach is taken to setting derating factors for some technologies in the capacity market.

of a ‘constrained ALF’ is not a new concept per se as this is simply what the combination of ALF and sharing factors attempts to proxy for in generation charges for intermittent plant. Based on its value, the Year Round credit for storage could be adjusted by a value anywhere between 0% and 100%.

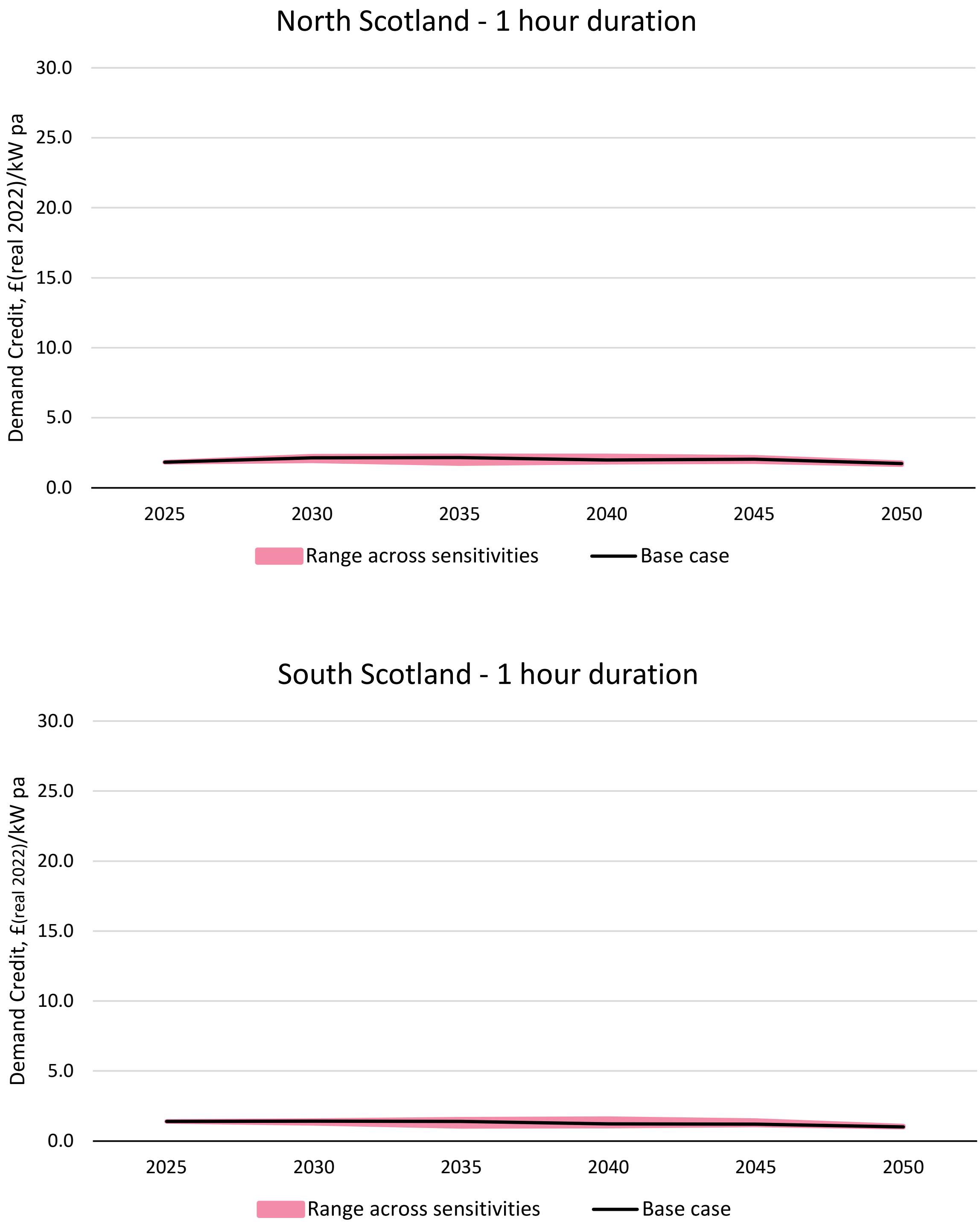
It is important to note that this approach would not be consistent with the treatment of a peaking plant in a negative generation charging zone, which arguably is the closest analogy to a demand source in a negative demand charging zone. Therefore, if such an approach were taken forward, it may also be appropriate to consider this for generation in negative generation charge zones as well.

A “constrained ALF” approach to the design of the demand credit could lead to different levels of credit for different storage technologies, or specific plants, depending on their expected contribution to the relief of network constraints (measured by the average demand load factor for the storage unit during periods of constraint). For example:

- LDES may be expected to charge more during constrained periods than SDES because it is able to charge for longer periods without hitting capacity limits. If this is the case, then it would be justified for LDES to receive a greater demand credit than SDES.
- Different storage plants may also be subject do different operational constraints, which would affect their ability to charge during constraints e.g. the demand constrained ALF for a pumped storage hydro asset with significant “run-off” would, all else equal, be expected to be lower than an equivalent asset without such a constraint on its operation.

We illustrate this constrained ALF approach to the demand credit using the modelling results for 2035 set out in Section 5. We present the potential demand credit for storage units of different durations located in north and south Scotland in Figure 23, Figure 24 and Figure 25 below for each of the different background scenarios that have been modelled. These are based on the ALFs during all constraints.

Figure 23 Illustrative Demand Credit – 1 hour duration

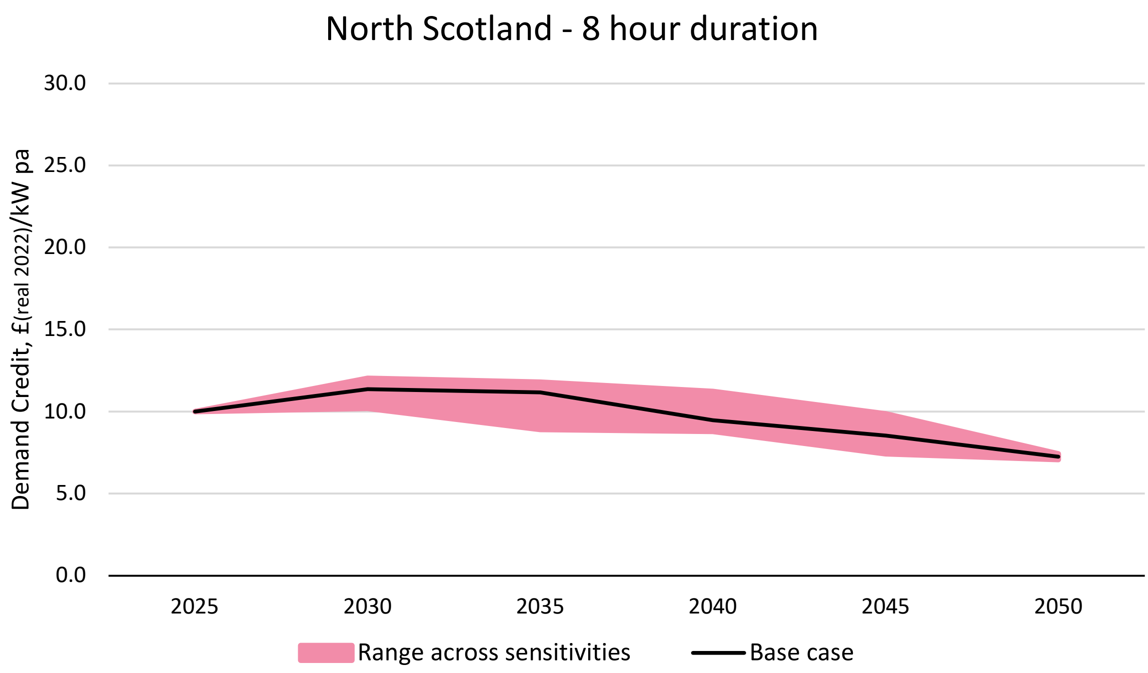


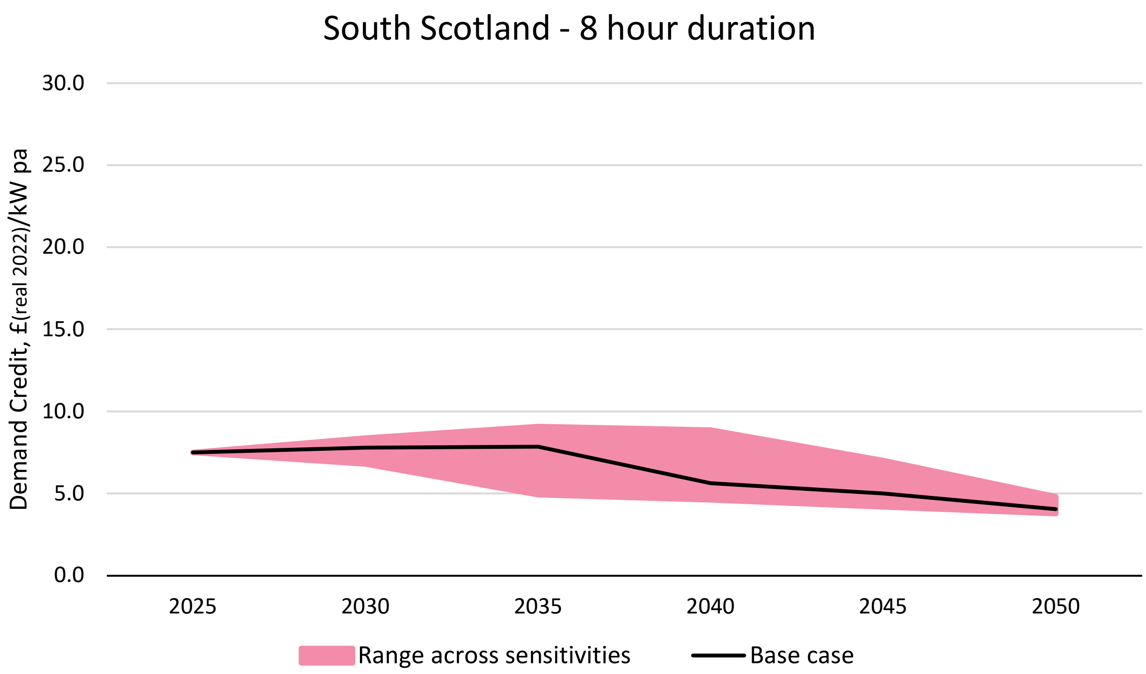
Source: LCP Delta

Note: This is calculated using demand TNUoS forecasts from NGESO, multiplied by the charging load factors (during all constrained periods). The Year Round element of locational demand tariff in 2028/29 is forecast by ESO to be £43.51 in the Northern Scotland zone and £28.92 in the Southern Scotland zone (in £2022 prices); this is used for all years after 2025.

The illustrative demand credit calculated for the Base Case, ranges from only £1-2/kW for 1 hour storage through to around £11-21/kW for 23-hour storage in Northern Scotland.

Figure 24 Illustrative Demand Credit – 8h duration



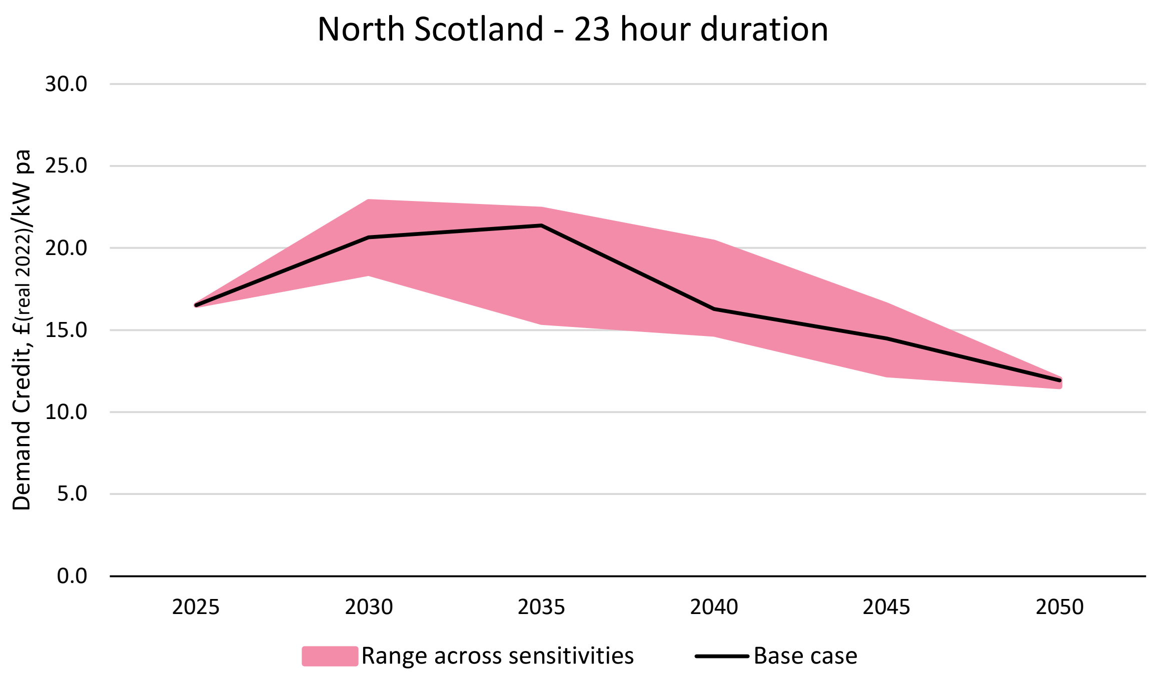


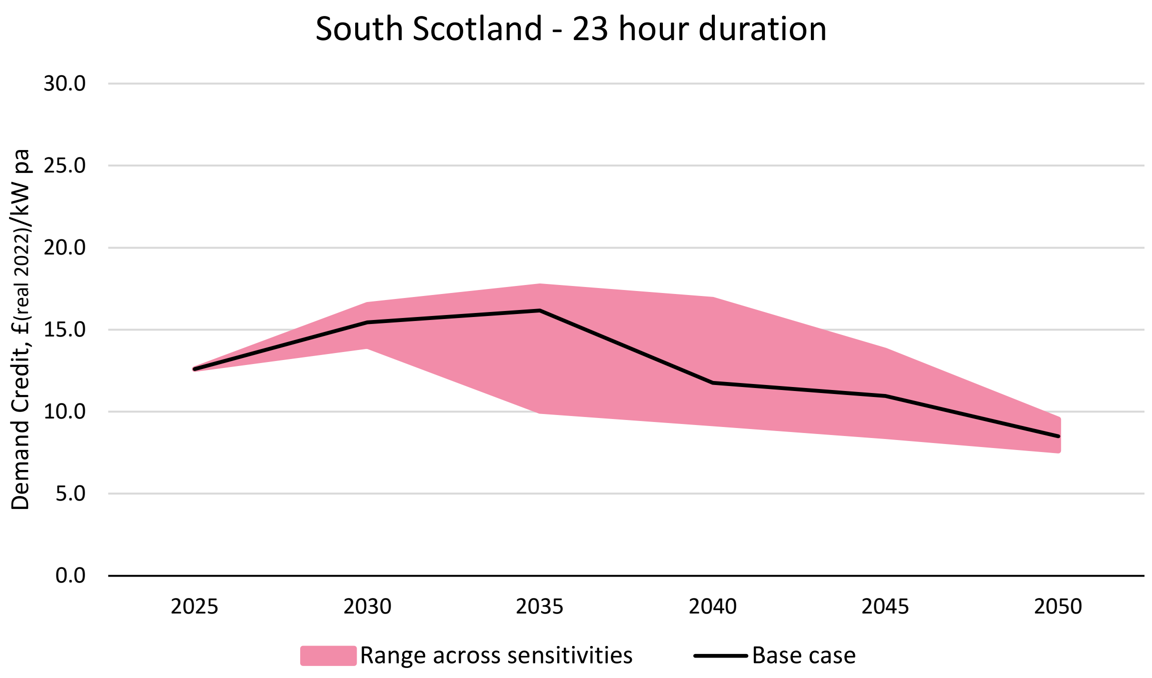
Source: LCP Delta

Note: This is calculated using demand TNUoS forecasts from NGESO, multiplied by the charging load factors (during all constrained periods) calculated for the modelled year of 2035. The Year Round element of locational demand tariff in 2028/29 is forecast by ESO to be £43.51 in the Northern Scotland zone and £28.92 in the Southern Scotland zone (in £2022 prices).

In the High Wind case, the illustrative demand credit is smaller than in the Base Case for both North Scotland and South Scotland. For 1 hour storage the credit is around £1/kW, whilst for 23-hour storage the credit reaches £11-19/kW in Northern Scotland. These lower credit levels reflect lower modelled constrained ALFs for storage operators in these zones than in the Base Case.

Figure 25 Illustrative Demand Credit – 23h duration





Source: LCP modelling

Note: This is calculated using demand TNUoS forecasts from NGESO, multiplied by the charging load factors (during all constrained periods) calculated for the modelled year of 2035. The Year Round element of locational demand tariff in 2028/29 is forecast by ESO to be £43.51 in the Northern Scotland zone and £28.92 in the Southern Scotland zone (in £2022 prices). .

In the High Network Build case the illustrative demand credit is smaller than in the Base Case for both North Scotland and South Scotland but higher than in the High Wind case. For 1 hour storage the credit is around £1/kW, whilst for 23-hour storage the credit reaches £11-23/kW. These intermediate credit levels reflect intermediate modelled constrained ALFs for storage operators in these zones.

6.3 Summary of the possible design options for CMP405

In the last part of this section we summarise the different design options that we have discussed and set out their advantages and disadvantages.

Table 1 Design options for the CMP405 demand credit

Option	Description	Advantages	Disadvantages
Volume-based credit	Credit set ex post based on annual (pumping) volume (MWh)	Simple to implement, including for new plants as set ex post. Annual volume likely to have some relationship with contribution to relieving constraints	Volumetric-based charges could distort dispatch. Need to convert a £/kW Year Round charge into £/MWh charges
Capacity-based credits			
Capacity-based (MIL)	Credit set based on MIL	Simple to implement for new plant, and no obvious distortion risk	Does not reflect the impact of different types of storage plant on constraints and avoided network costs
Capacity-based (ALF)	Credit set based on MIL x ALF	Is similar to the TNUoS Year Round generation charge methodology for Conventional Low-carbon plant and is relatively simple. No obvious distortion risk.	Differentials in charges may inaccurately reflect the contribution to avoiding network costs and therefore may distort investment in different storage assets.
Capacity-based constrained ALF	Credit set based on MIL x ALF during constraints	Consistent with approach to application of sharing factors for Intermittent plant generator TNUoS charges. Better reflects the contribution of different storage plant to avoiding network costs. No obvious distortion risk.	Practically, difficult to set value of constrained ALF for new plant ex ante and may require modelled values until observed data available. Risk that if system deviates significantly from optimal expansion path of network, observed constrained ALF may not reflect value of storage in optimal system. May require modelling an optimised constrained ALF

Source: Frontier Economics

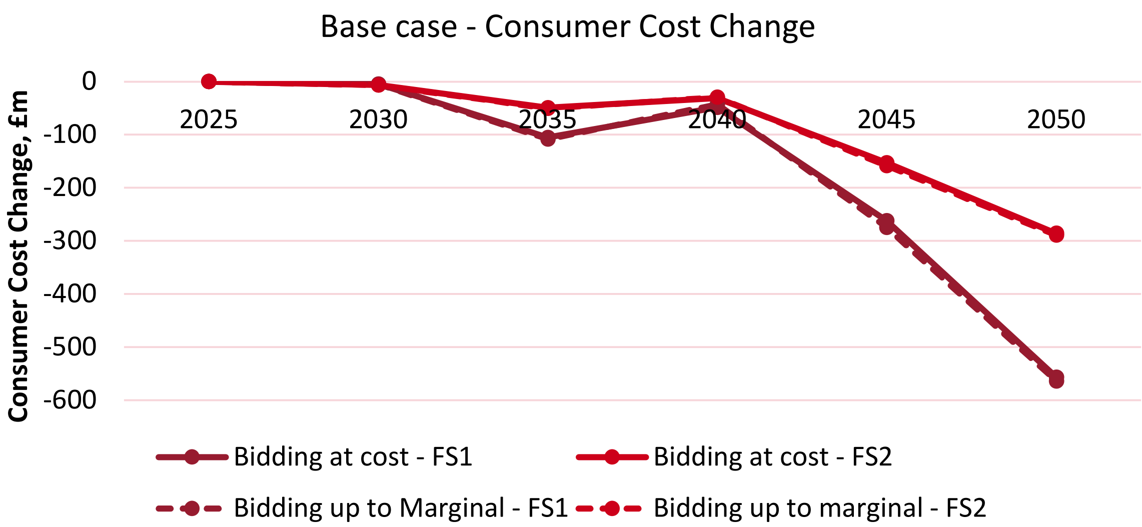
In line with the focus of CMP405, we have so far only discussed options that relate to storage technologies. However, we think that the principles that have underpinned our assessment of options would equally apply to charging options for other flexible demand technologies e.g. electrolysers. In other words, the chosen approach for storage could later also be applied to other types of demand.

Annex A - Plant bidding assumptions

We assume that all plants bidding in the locational balancing mechanism do not seek to make profit from their bids. This assumption of bidding at cost (as opposed to bidding up to the marginal unit) has no impact on plant dispatch in locational balancing or on system cost but will affect consumer costs.

We would in practice expect some plants to make profit from locational balancing actions. However, given the uncertainty regarding the precise bidding behaviour of all plants and the interpretation of regulations that seek to restrict excessive profits due to congestion management, we have assumed for simplicity that plants break even. We have also modelled an alternative approach where all plants make profits based on bidding up to the marginal unit and the impact on consumer costs is negligible. This is shown below in Figure 27.

Figure 26 Consumer Cost change with different bidding strategies



Source: LCP modelling

:

Additionally, we assume that new build onshore wind, offshore wind, and solar CfD plants will adjust their strike prices in the future to account for any additional revenues earned due to storage reducing their energy curtailment. This means that we essentially assume that these plants make the same level of return between the counterfactual and factual scenarios.

Annex B – Modelling Assumptions in Detail

B.1 Comparison of FES 2022 and FES 2023 System Transformation Scenarios

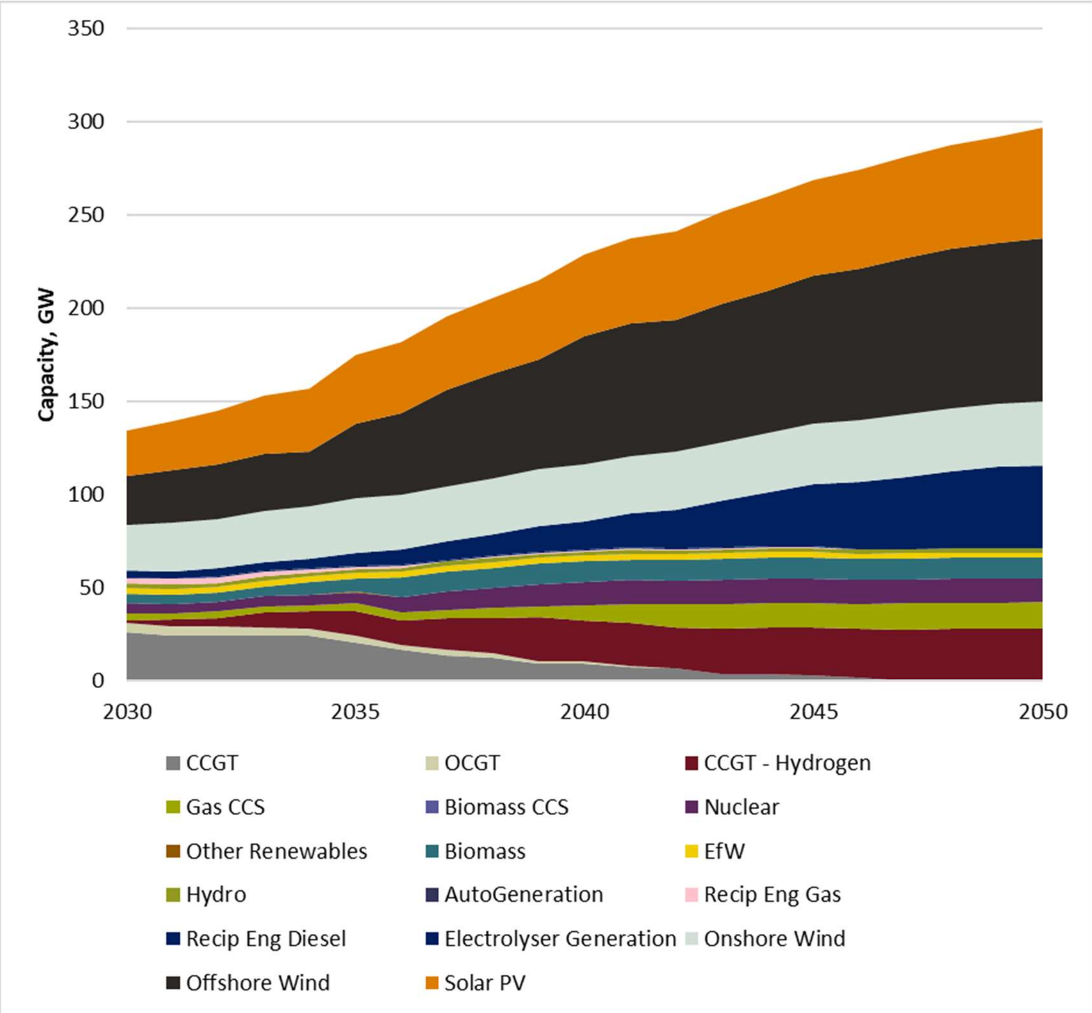
Table 2 Comparison of key System Transformation scenario assumptions from FES 2022 to FES 2023

	2030		2035		2050	
	FES 2022	***FES 2023***	***FES 2022***	***FES 2023***	***FES 2022***	***FES 2023***
Annual demand (TWh)	321	325	392	400	716	678
Peak demand (GW)	64	63	73	73	100	101
Installed capacity (GW)	171	172	225	225	318	344
Wind and solar capacity (GW)	90	89	136	134	189	213
Interconnector capacity (GW)	13	12	13	16	16	16
Storage capacity (GW)	15	17	19	20	40	41
Storage capacity (GWh)	47	51	56	59	113	116

Source: National Grid ESO

B.2 Capacity Mix of FES 2022 Scenario used in the modelling

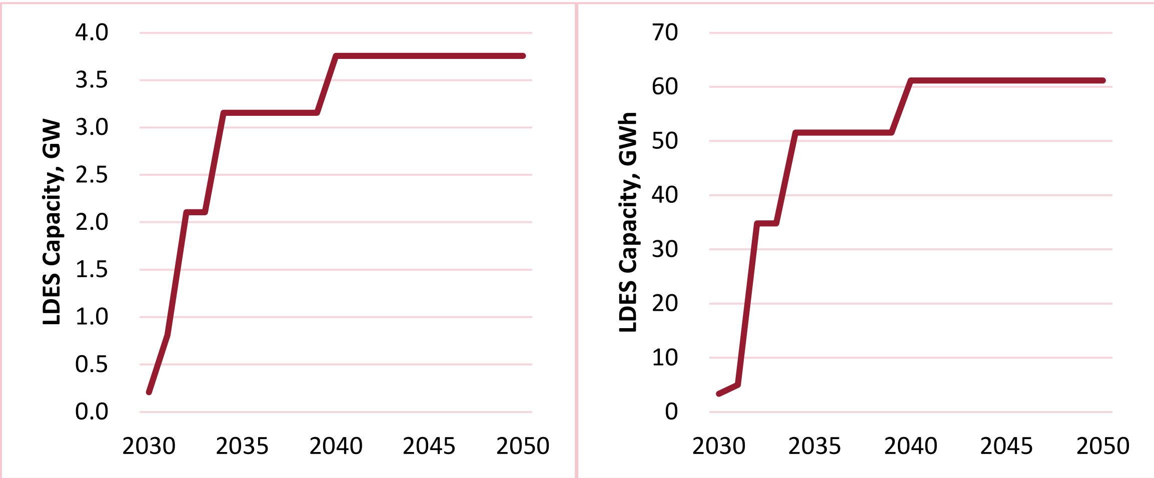
Figure 27 Capacity mix (excl. storage)



Source: LCP Delta

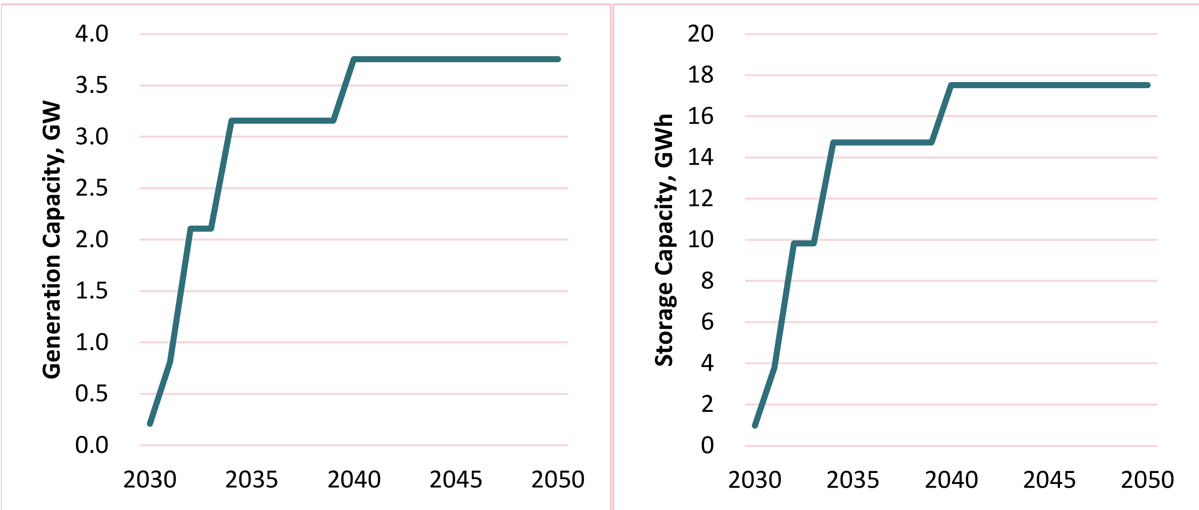
B.3 Additional LDES Capacity used in FS1 and FS2 Scenarios

Figure 28 Additional LDES Capacity (GW and GWh) in FS1



Source: LCP Delta

Figure 29 Additional Shorter Duration Storage Capacity (GW and GWh) in FS2



Source: LCP Delta

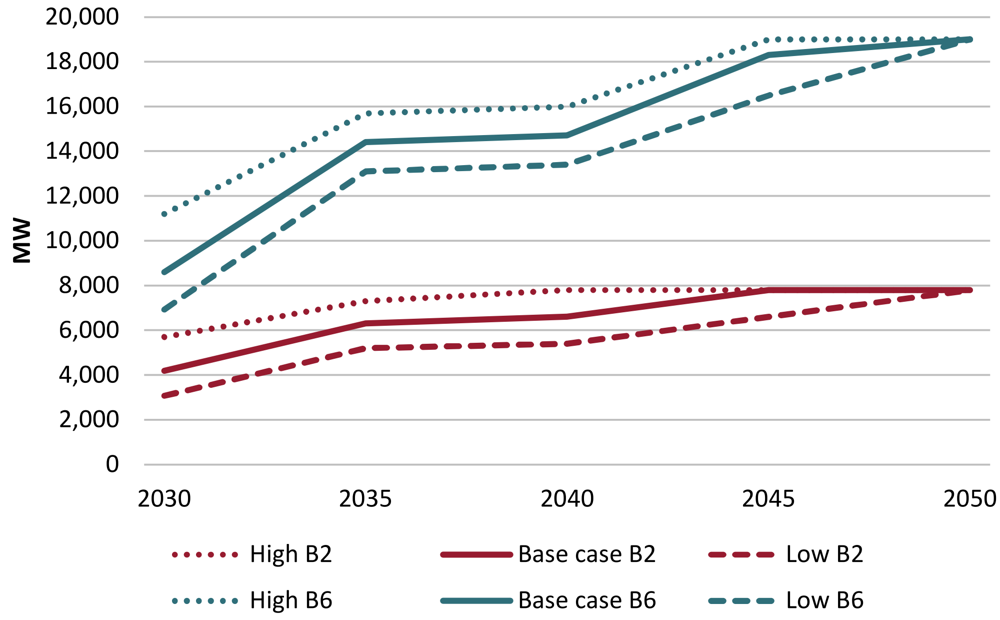
B.4 Transmission Network Build

In the Base Case, High Wind case and Low Wind case, we assume that the level of additional network capacity added to reinforce the B2 transmission boundary (between North and South Scotland) and B6 transmission boundary (between South Scotland and England) are "optimised". By this we mean that the capacity of the network reflects the outcome of a CBA which balances the incremental costs of network build with the savings it brings through reduced constraint costs.[45] We have adjusted network capacity up to the point where its incremental cost per year is equal to the additional constraint costs that would be incurred each year if the capacity was not added.

For this optimised network build approach, we assume a capital cost of £70m per year for every 1,500MW of network reinforcement (based on previous analysis by LCP Delta for SSEN). We performed iterative model runs to get to (or as close as reasonably practicable to) the level of transfer capacity across the B2 and B6 boundaries in each year (with a focus on the years 2030, 35, 40, 45 and 50) where:

- the capital cost of adding further transfer capacity is greater than or equal to the resultant saving in constraint cost; and
- the additional constraint cost incurred when the boundary capacity is any lower is greater than or equal to the capital cost saving.

Figure 30 Transfer capacity – B2 and B6 transmission boundaries



Source: LCP Delta

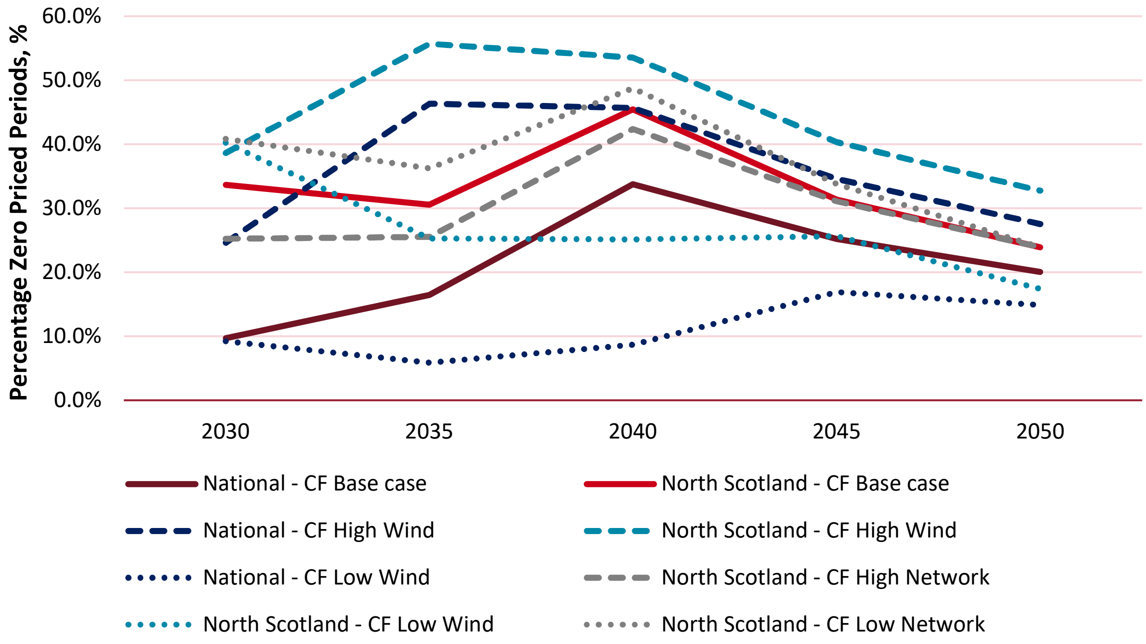
[45] This optimisation is focused purely on the trade-off between constraint costs and network build costs. It does not consider the impact on carbon.

Annex C - Further wider system modelling results

Error! Reference source not found. below shows the percentage of periods with a price of zero or below. In the High Wind case, locational prices for North Scotland in 2035 are zero in around 56% of hours. As we noted above, it was this outcome that motivated the definition of our Base Case to include a 5 year delay to the deployment of wind capacity.

Additionally, in the Low Wind case, wholesale prices are zero in around 6% of hours and North Scotland prices are zero in around 25% of hours in 2035. Lower wind levels mean that wind is less commonly setting the price (at zero), so we see fewer periods of zero prices.

Figure 31 Proportion of zero priced periods – North Scotland



Source: LCP Delta
Note: This graph shows the percentage of time that the locational price (a proxy for BM price) is less than < £1/MWh.

CF Base Case - Statistics on the length, depth, and frequency of constraints

The following charts show results for the counterfactual Base Case with regards to constrained boundaries. A boundary is constrained when the unconstrained flow across the boundary is modelled to be over the maximum capacity during national wholesale market dispatch. After locational balancing, a constrained boundary will have flow at its maximum capacity.

Boundary Constraint Depth

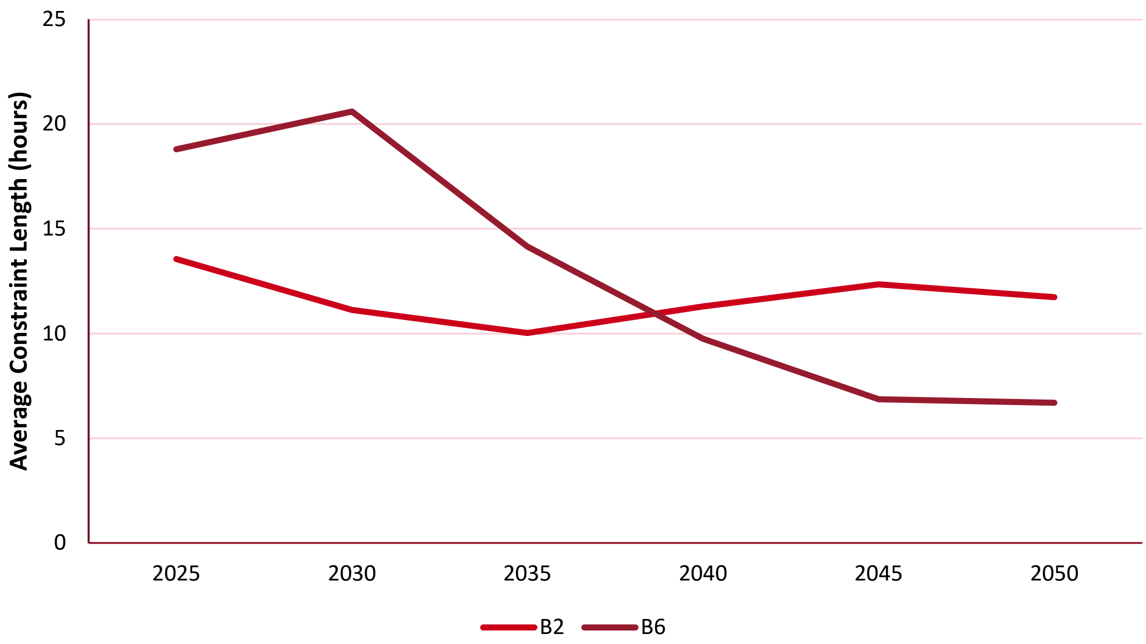
By considering boundary flows during national wholesale dispatch, we can assess the amount of excess flow relative to the boundary's capacity. This excess flow will require generation to be turned down (or demand to be turned up) in locational balancing. The graph below shows the average excess flow during constrained periods. There is unconstrained excess flow during constrained periods averaging between 4,000MW and 6,000MW over B6 in the Base Case, trending slightly upwards through to 2050. Over B2 the unconstrained excess flow averages just over 1,000MW in 2025, but rises to almost 4,000MW by 2050.

Figure 32 Average unconstrained excess flow over boundary during constrained periods

Boundary Constraint Length

When a boundary is constrained, we can observe how many consecutive hours the constraint lasts for. Longer constraints will limit shorter duration storage's ability to charge and relieve the constraint. The graph below shows the average length of time a boundary is constrained when a constraint occurs.

Figure 33 Average length of time boundaries are constrained for when a constraint occurs



Frequency of constraints

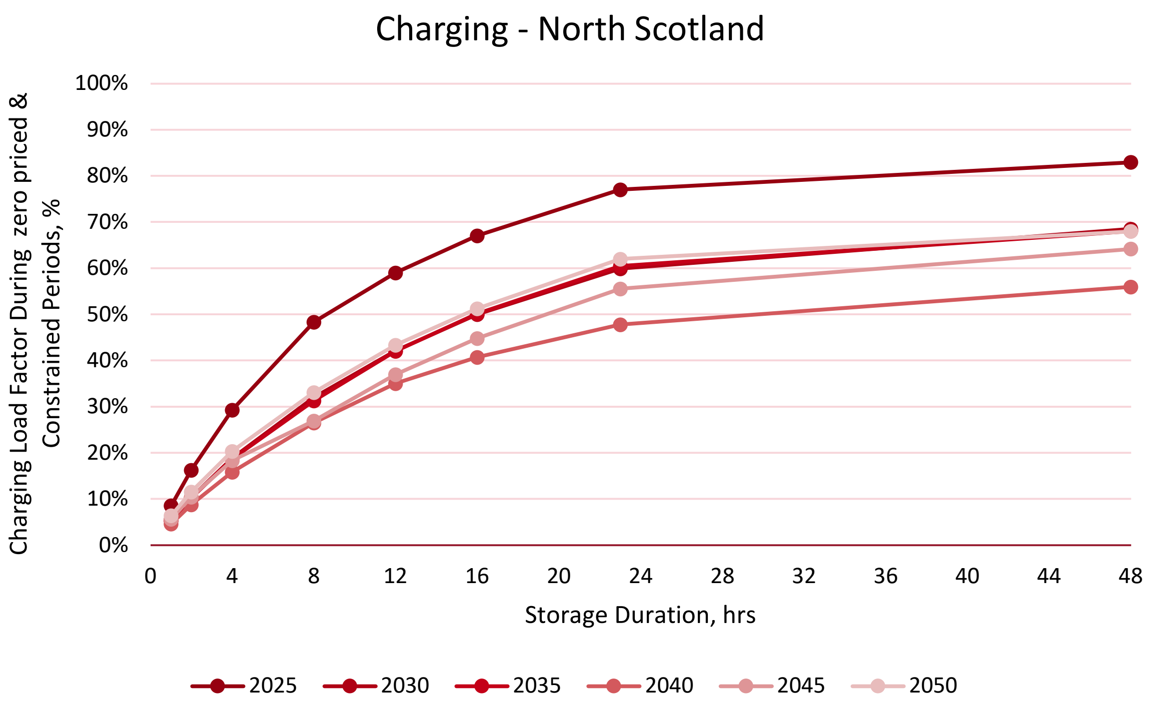
A constrained period is a continuous period of time where a boundary is at maximum capacity. This period of time varies as shown on the previous chart. The chart below shows the number of these constrained periods that occur in a year. For example, the boundary B2 has an average constraint length of 10 hours in 2035 and there are 141 of these constrained periods in the year. B6 has a similar number of constrained periods in 2035 but they last for an average of 14 hours.

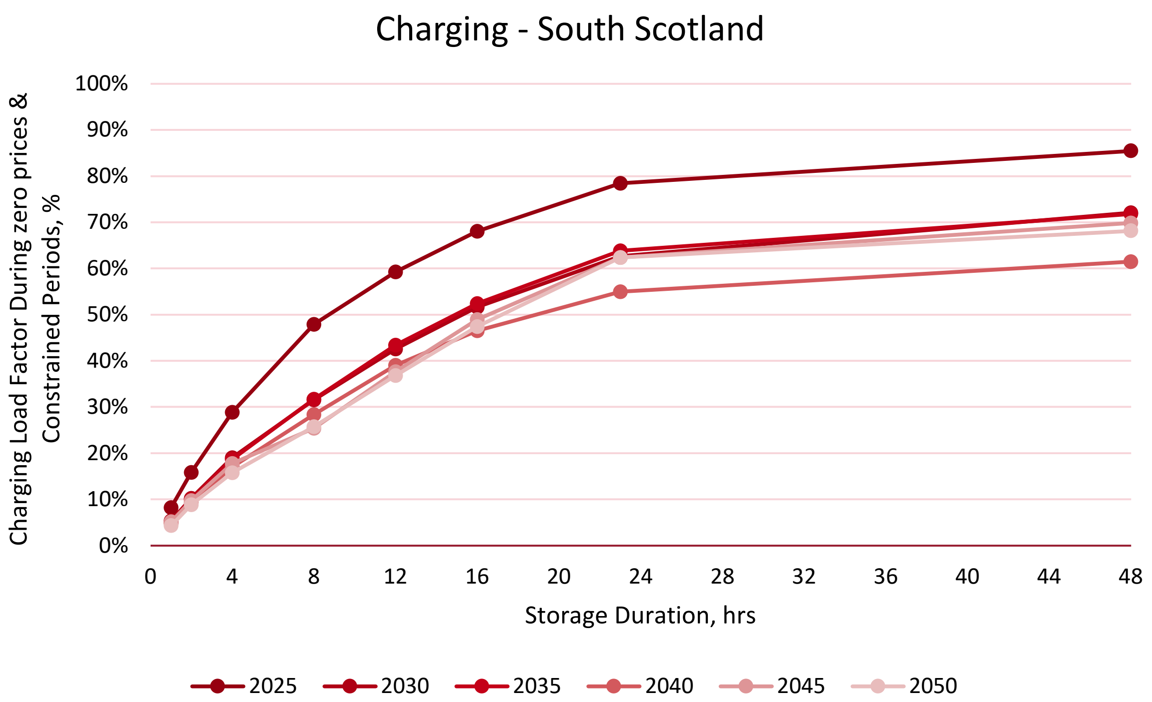
Figure 34 Frequency of constrained periods per year


250
200
150
100
50
0
Number of Constraints
2025
2030
2035
2040
2045
2050
B2
B6

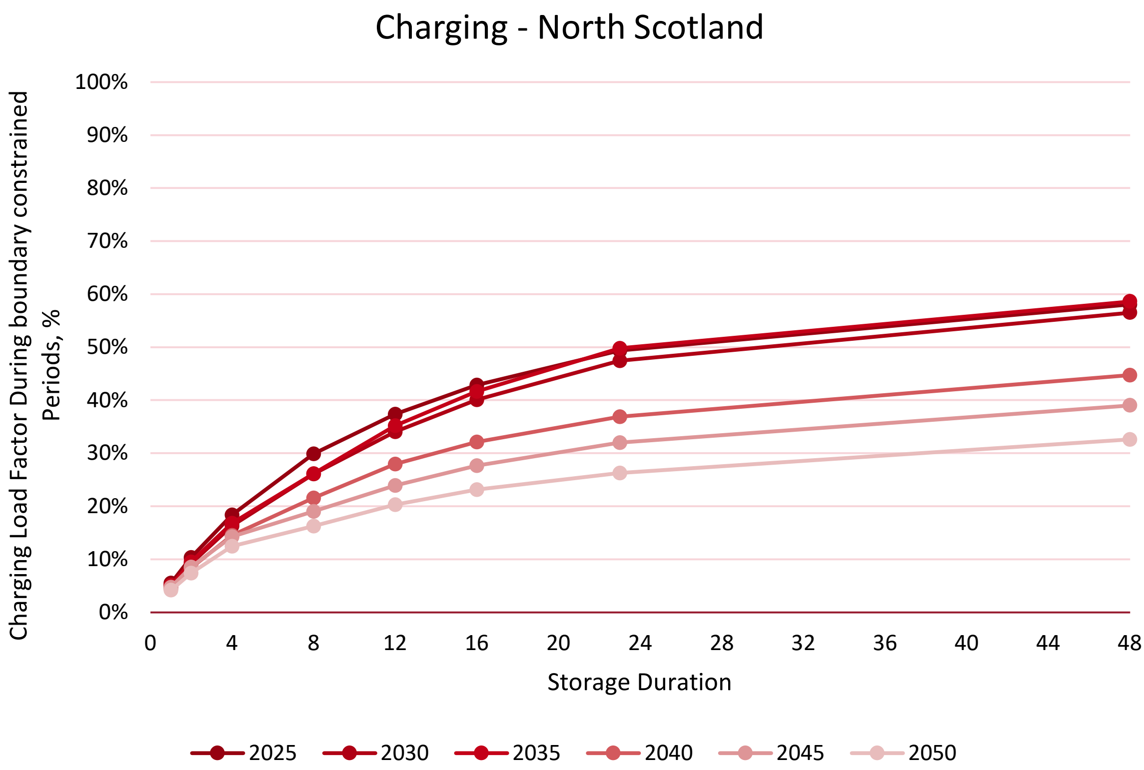
Annex D – Additional Charge Graphs

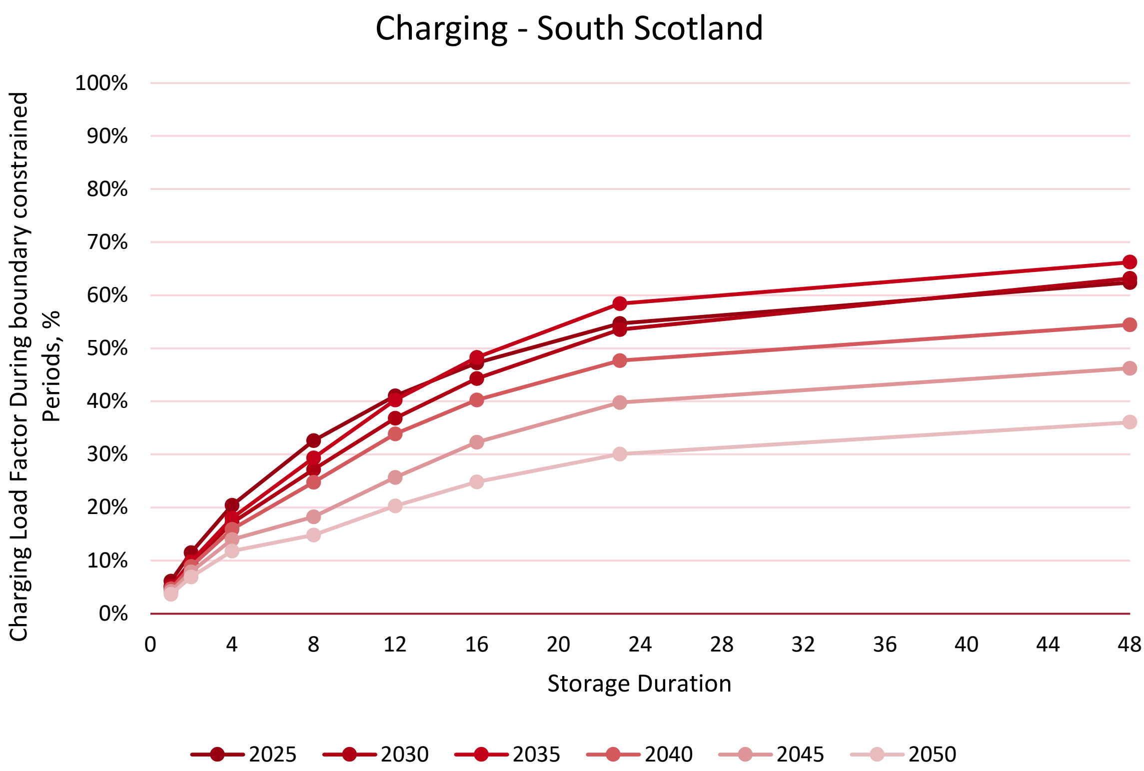
D.1 CF Base Case – Charge Load factors during constraint periods with zero prices



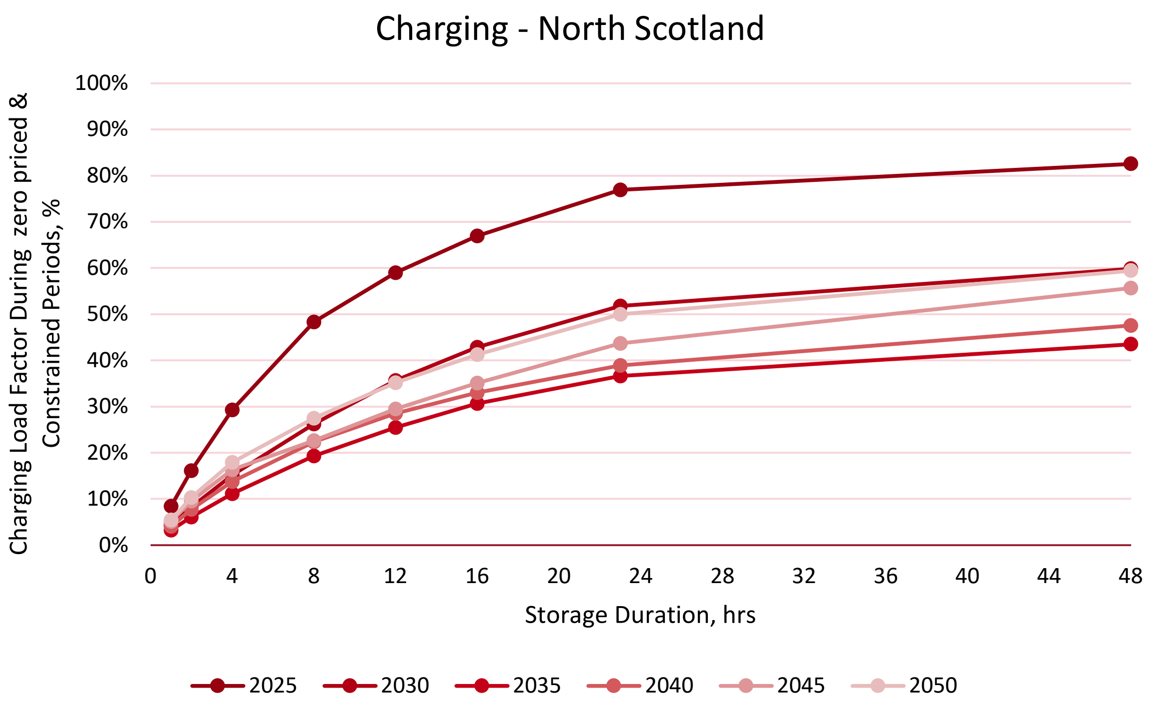


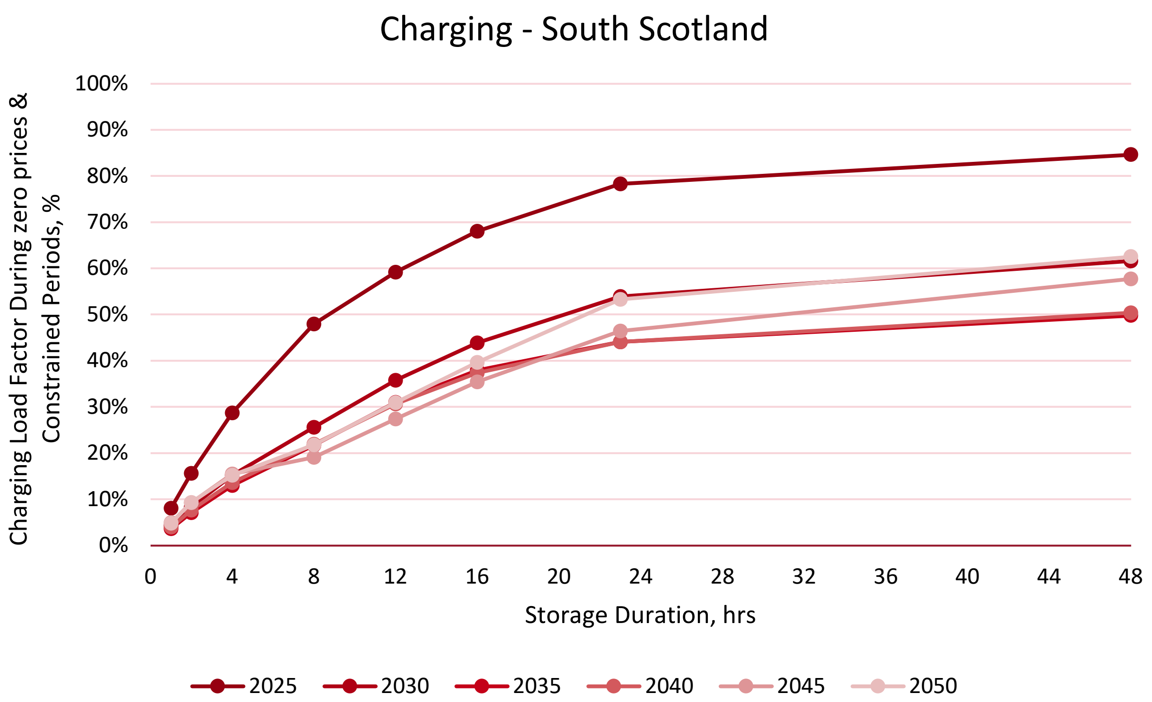
D.2 CF Base Case – Charge Load Factors during all constraints



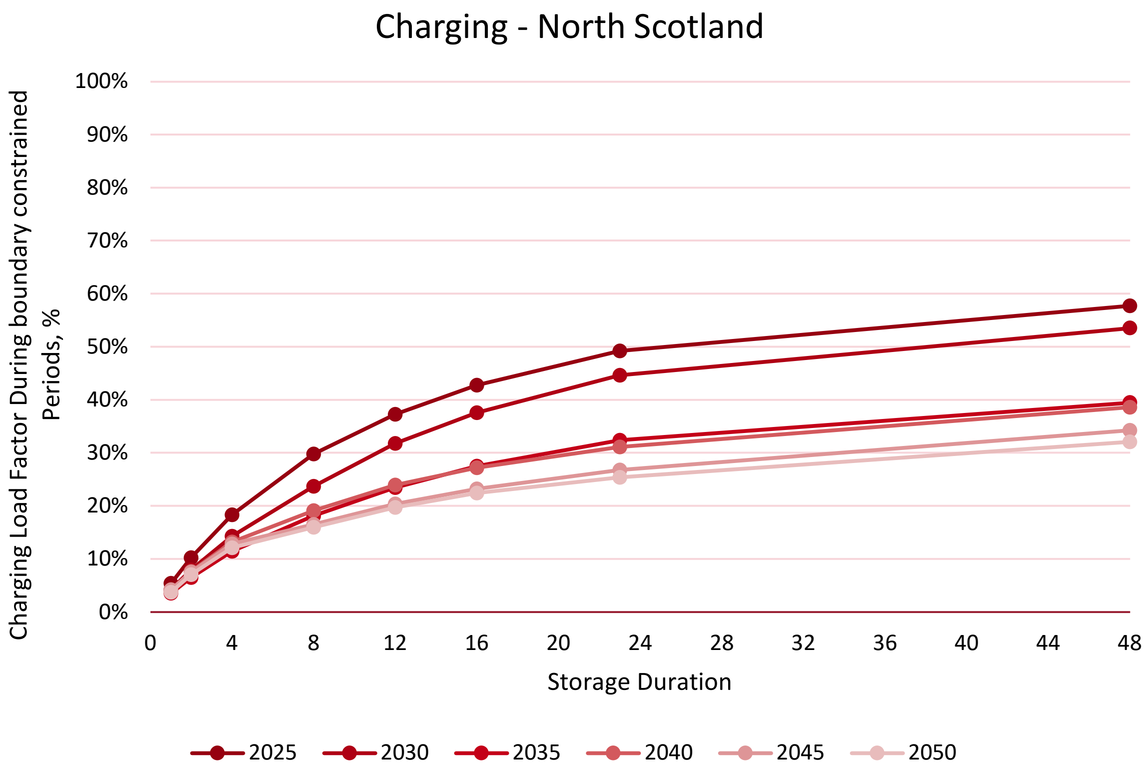


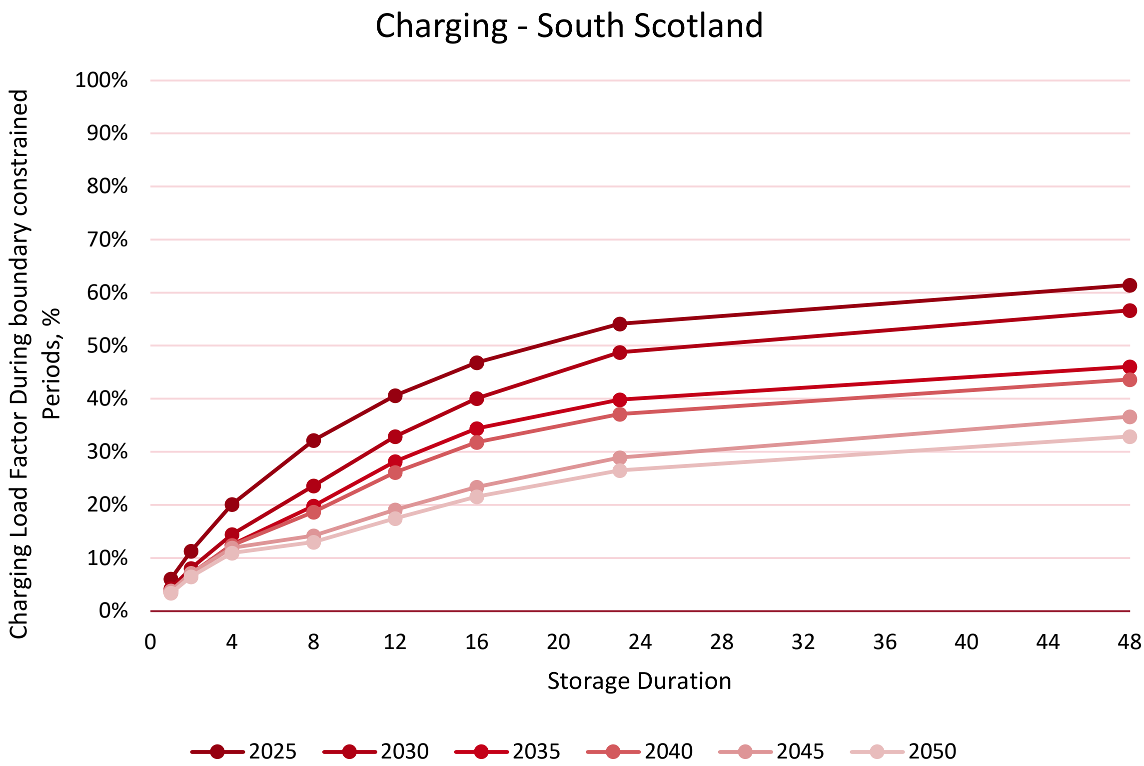
D.3 CF High Wind case – Charge Load Factors during constraint periods with zero prices



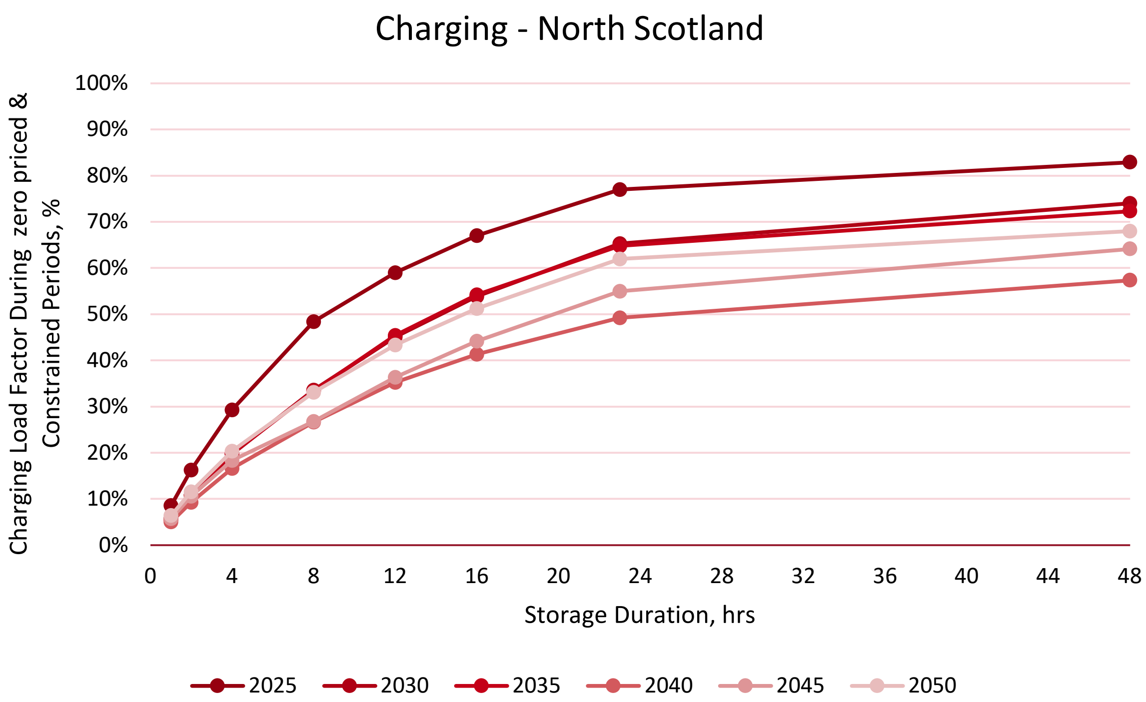


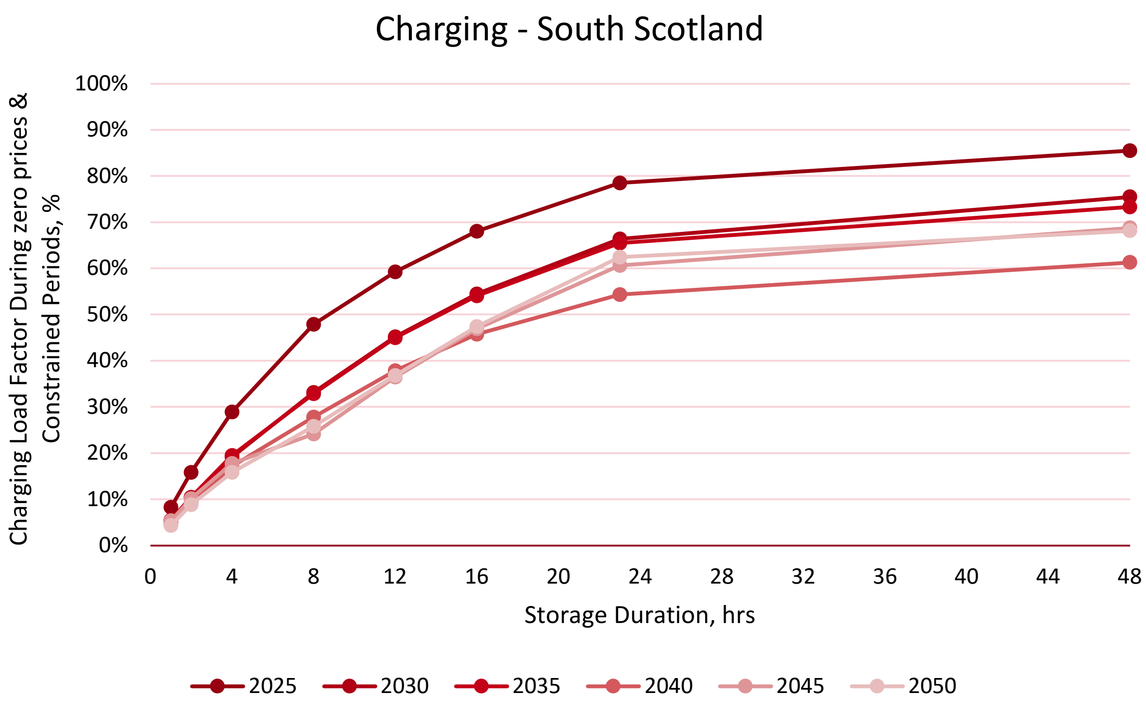
D.4 CF High Wind case – Charge Load Factors during all constraints



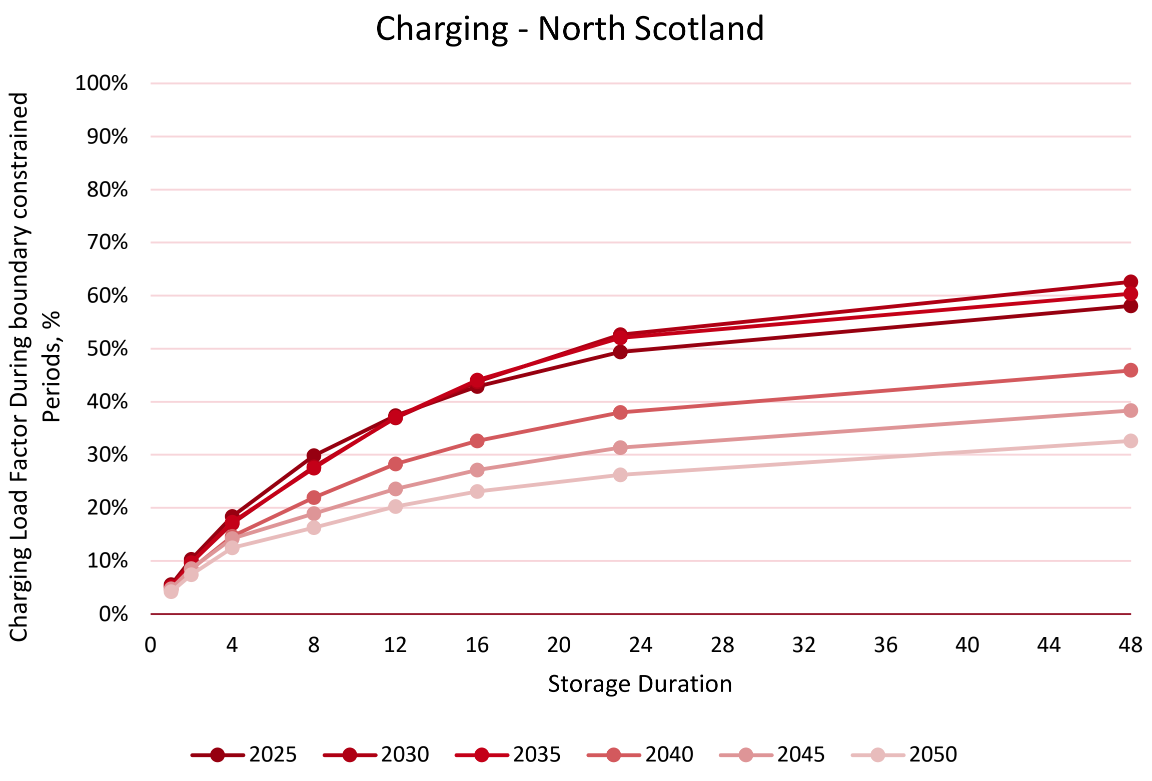


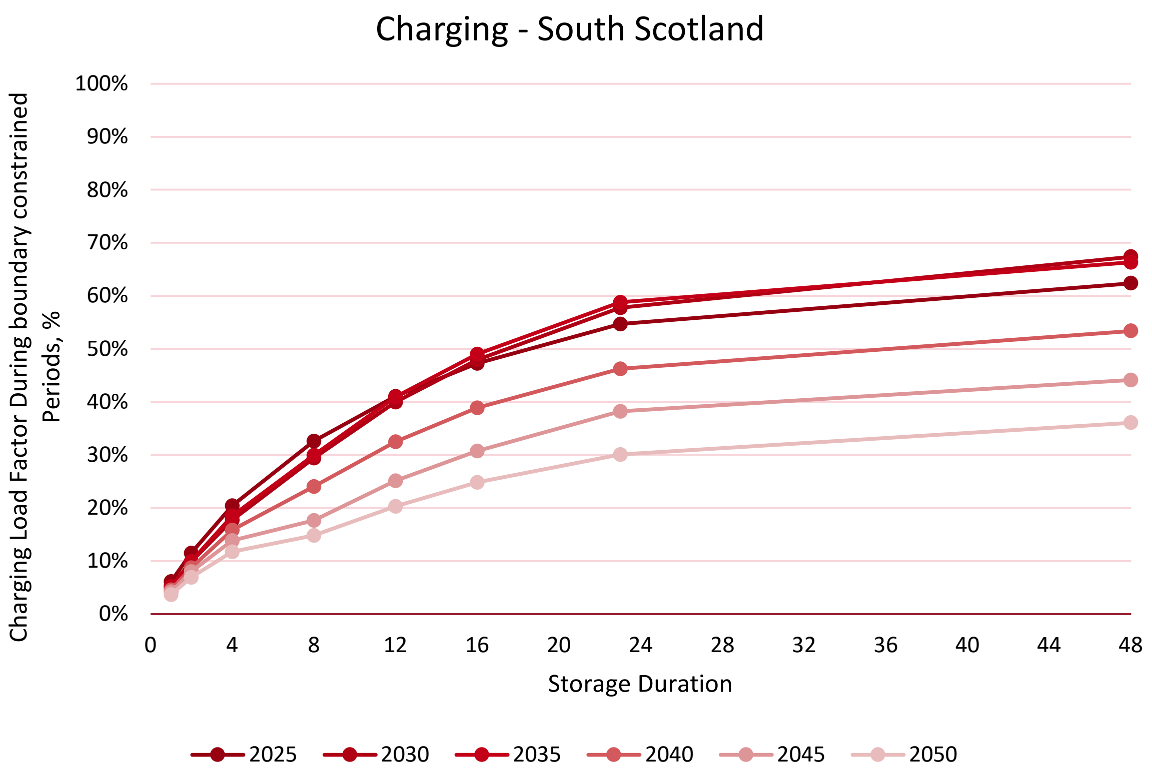
D.5 CF High Network Build case – Charge Load Factors during constraint periods with zero prices



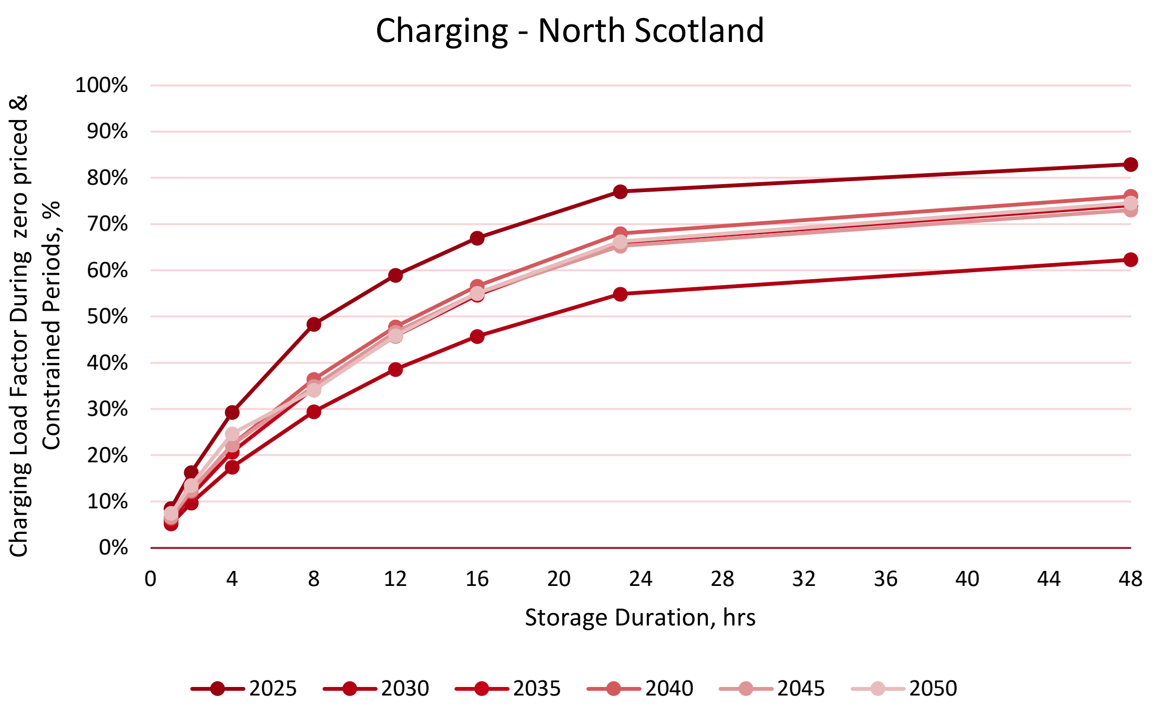


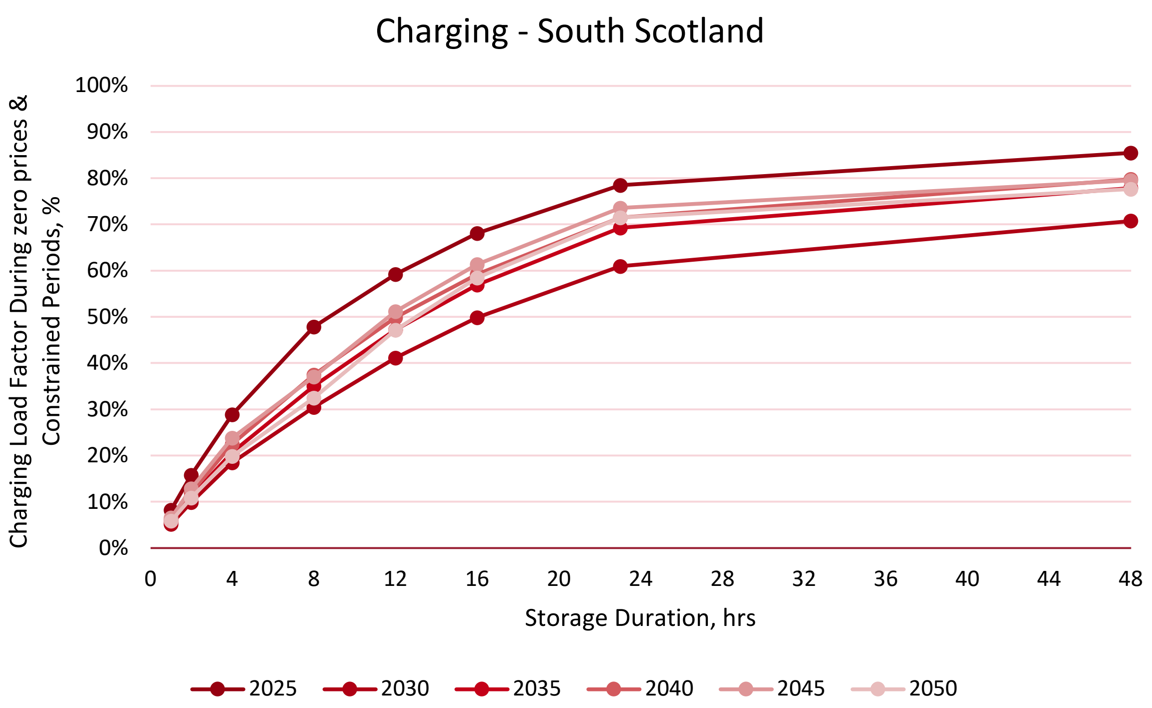
D.6 CF High Network Build case – Charge Load Factors during all constraints



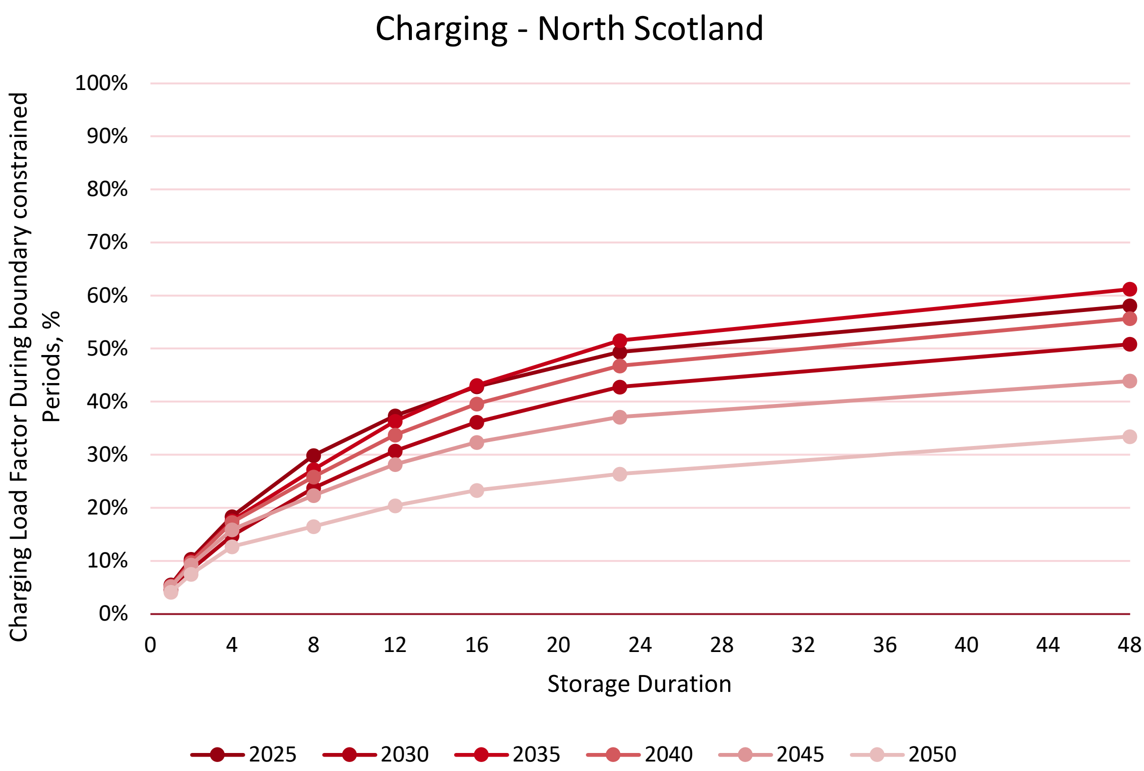


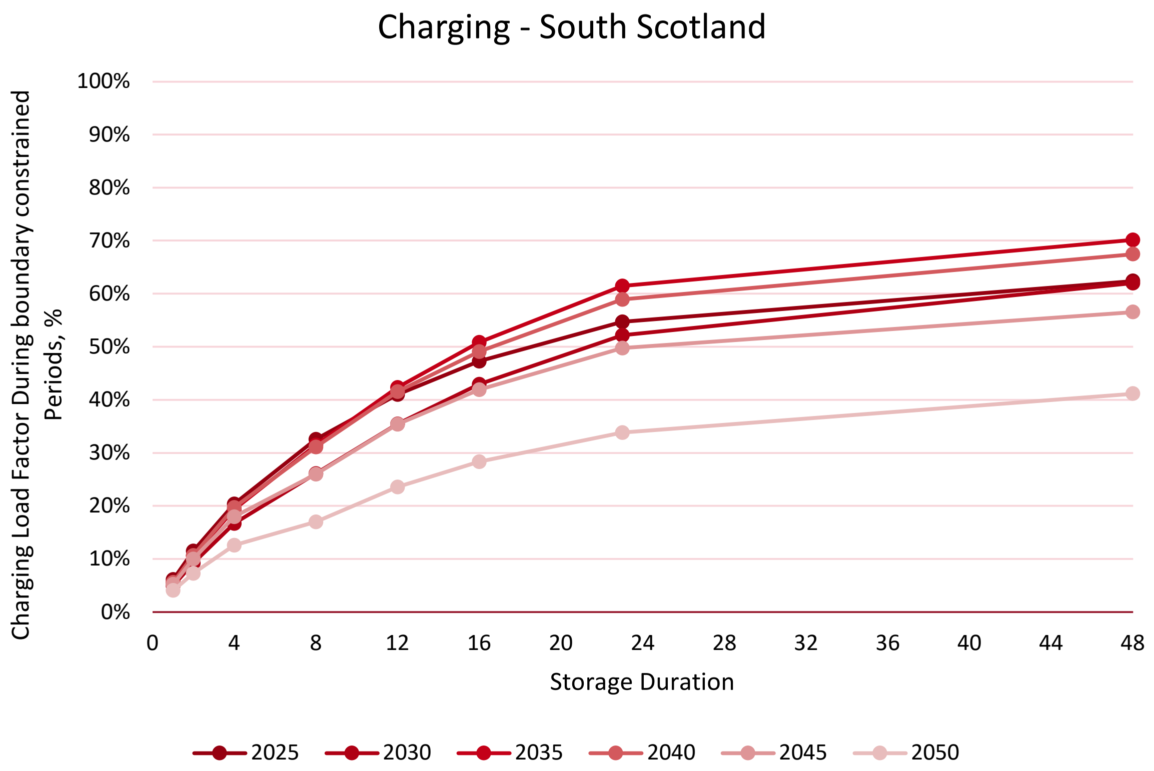
D.7 CF Low Wind case – Charge Load Factors during constraint periods with zero prices



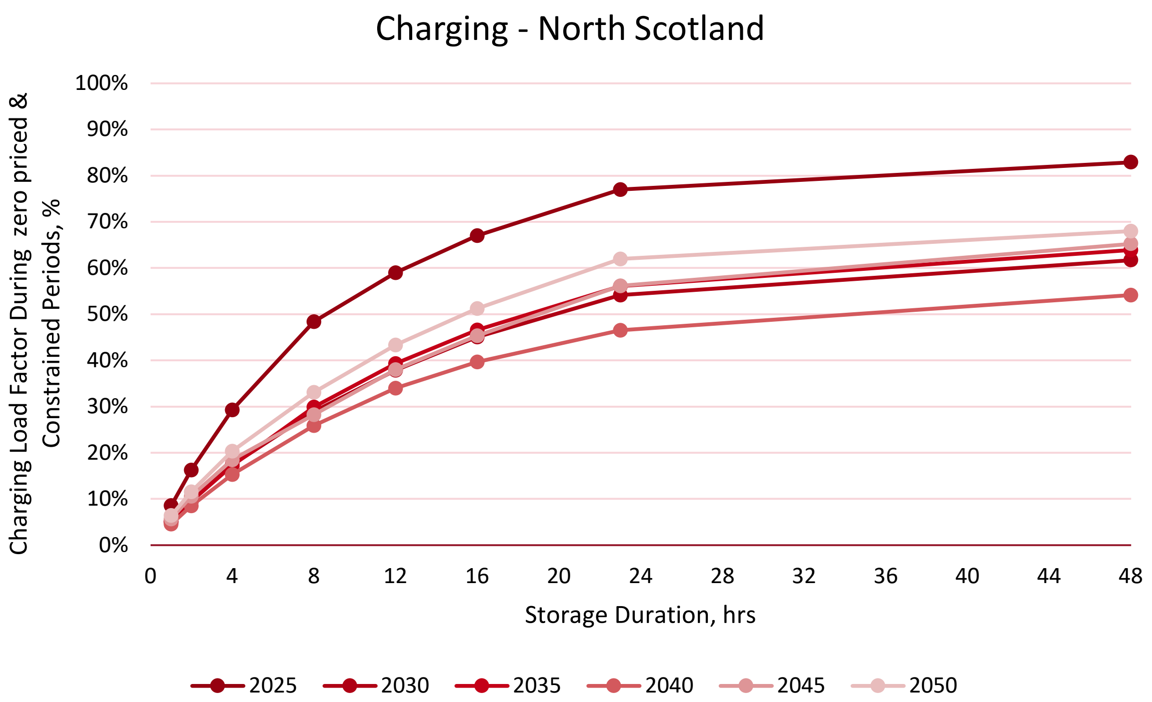


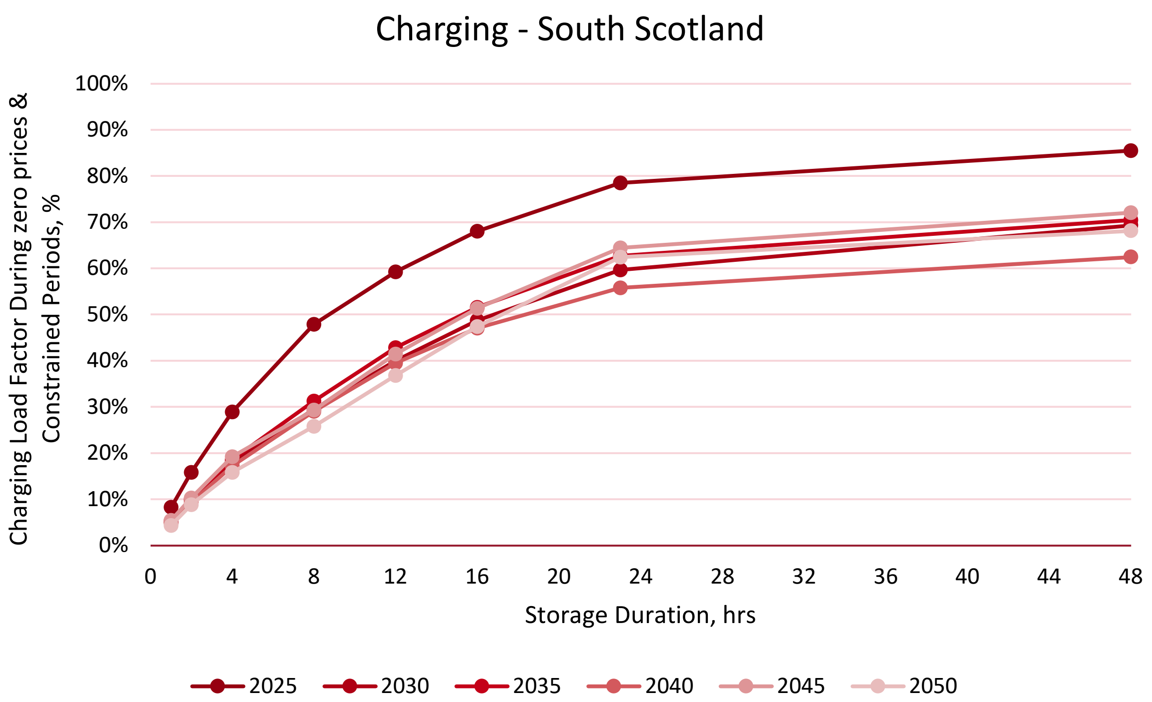
D.8 CF Low Wind case – Charge Load Factors during all constraints



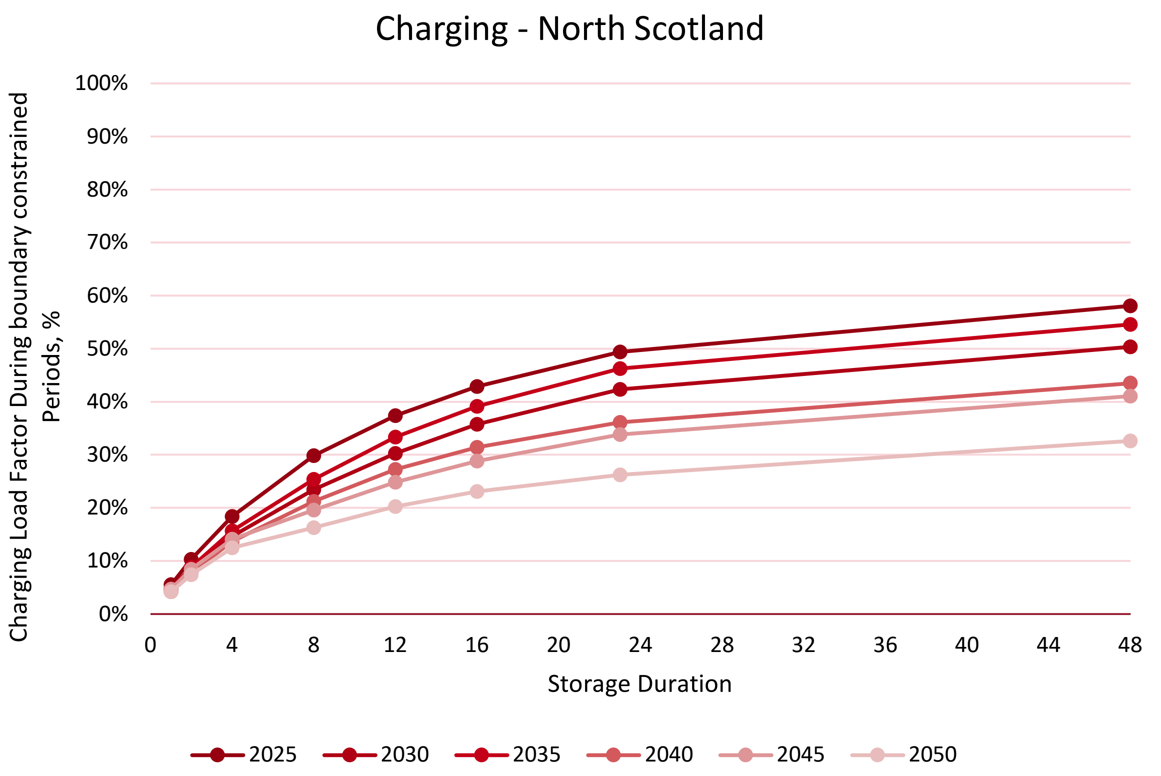

Charging - South Scotland
Charging Load Factor During boundary constrained Periods, %
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
4
8
12
16
20
24
28
32
36
40
44
48
Storage Duration
2025
2030
2035
2040
2045
2050

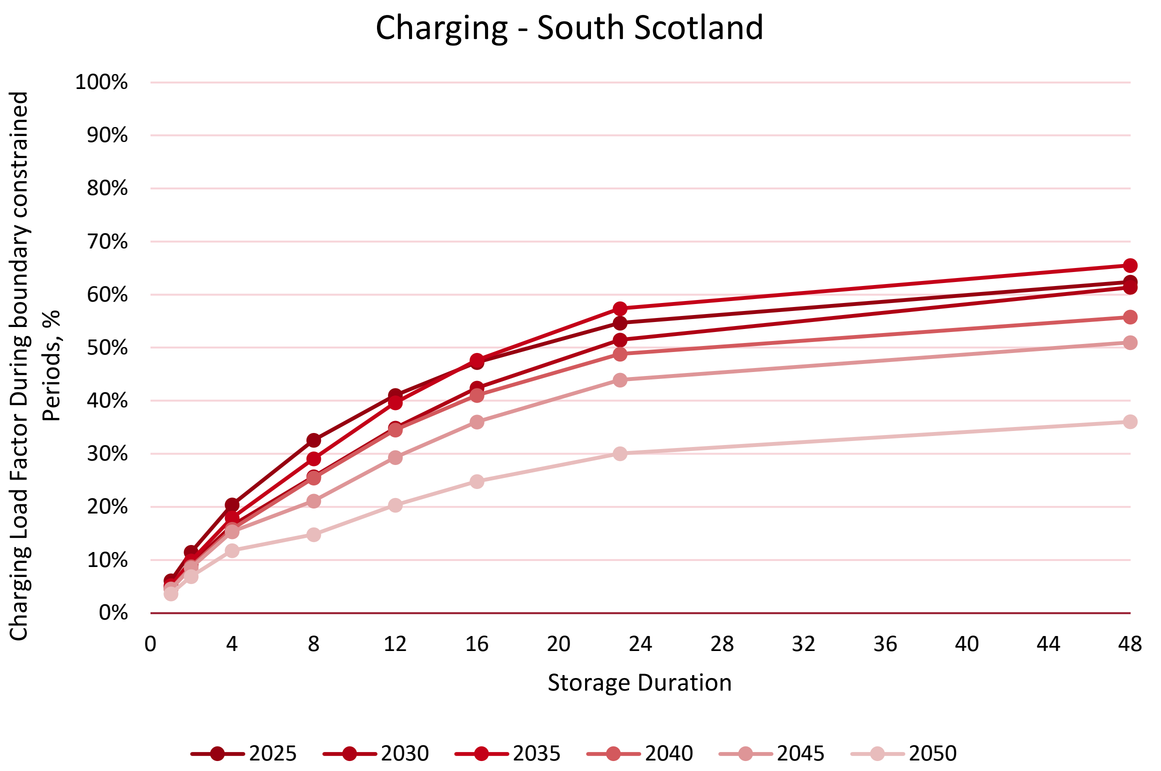
D.9 CF Low Network Build case – Charge Load Factors during constraint periods with zero prices





D.10 CF Low Network Build case – Charge Load Factors during all constraints





Annex E - Description of the LCP Delta EnVision model

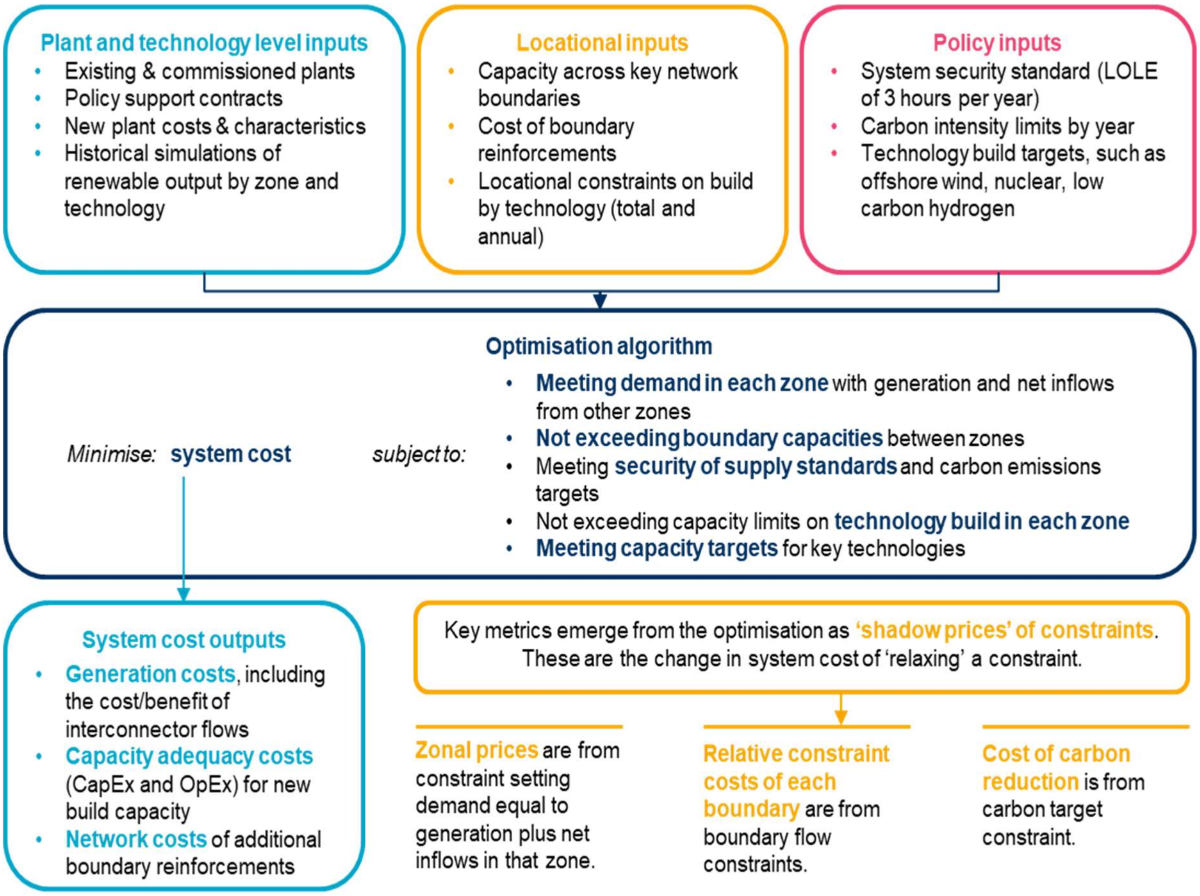
To understand the benefits that electricity storage can bring to the system and the operation of storage assets to relieve constraints, we have used LCP Delta's EnVision model, including its zonal constraints functionality. Using this model, the key boundary constraints in the GB system are captured, and the operation of different durations of storage can be assessed.

LCP Delta's market dispatch algorithm simulates the supply and demand in each hour based on market fundamentals at a zonal level. An optimisation algorithm is used to determine the flows between zones and the operation of storage. The model has options to run without and with boundary constraints to simulate national dispatch (current market arrangements with a single national dispatch price) followed but locational redispatch through the balancing market.

A locational dispatch simulates the market acting optimally given locational constraints. The difference between the locational and national dispatch, simulates the actions taken in locational balancing to fix constraints. Bid costs are calculated using the minimum or maximum (depends on if the plant is turning up or down) of locational 'price' and the bid that each plant used in locational dispatch. This includes using the national price as a reference price for CfD supported plants.

An overview of the model can be seen in Figure 35 below:

Figure 35 Overview of LCP Delta EnVision model



Source: LCP Delta

The main algorithm in the zonal constraints model optimises two days at a time and then records the data from the first day only. Most short duration storage will not need any more foresight than this. However, long duration electricity storage (LDES) operators will need to look over longer time scales to fully utilise their assets. To reflect this, LDES assets are modelled with greater foresight in the model. A "pre-optimisation" is run with a simplified version of the full optimisation over a longer optimisation period (typically 3-4 days at full hourly granularity) with LDES participating, providing it with foresight of prices over this period. The 'pre-optimisation' provides an assumption for the appropriate state of charge we would expect from each LDES at the end of each day, and this is fixed and applied in the standard optimisation afterwards. The standard optimisation is then run as normal, including LDES being re-dispatched to optimise its operation within each day with perfect foresight.

We do not model all storage assets over this longer optimisation period as it is not necessary for shorter duration storage that would typically have operating strategies that involve cycling one or more times per day. This allows an accurate representation of the competition between long and short duration storage and their different operating strategies.