DSO BENEFITS ASSESSMENT

A report prepared for SP Energy Networks

25 APRIL 2025

Contents

frontier economics

1 Executive Summary

SP Energy Networks (SPEN) has commissioned Frontier Economics to develop a framework for tracking and calculating benefits from its Distribution System Operator (DSO) activities. In the first instance, this is intended to support SPEN's DSO Performance Panel submission for 2024/25, where it is required to articulate and quantify the benefits of these activities. However, more importantly, it can be used as a tool to help SPEN continue to refine its DSO activities so that they provide greatest value for money to customers.

We have applied a systematic approach to assessing benefits, which is aligned with Ofgem's governance documents, HM Treasury's Green Book and Magenta Book, and the DSO Collaboration Panel's Common Appendix. This approach consists of three steps:

- **Identifying the relevant DSO activities**. SPEN has provided us with a grouped list of its DSO activities in the regulatory year 2024/25, which it developed with help from its Independent Net Zero Advisory Council (INZAC). We have stress-tested these activities with SPEN, ensuring that (as required for the DSO Performance Panel submission) they only relate to those activities which were carried out in the 2024/25 regulatory year. These could be new activities or build upon those carried out in previous regulatory years. We have also mapped the activities to Ofgem's 'baseline' expectations of DSO activity, to demonstrate that they are DSO-specific activities.

- **Developing logic models to link activities to benefits**. DSO activities are not valuable for their own sake, but because they produce benefits for society as a whole. We have used logic models to articulate the 'theory of change' for all DSO activities, demonstrating how they lead to benefits across the whole system, and to whom these benefits will ultimately accrue.

- **Developing quantification methodologies**. Wherever possible, we have carried out a Green Book style social cost-benefit analysis to quantify the expected benefits of SPEN's DSO activities in 2024/25. We have also (subject to available data) presented KPIs to quantify the activities, outputs, or outcomes that should eventually lead to benefits.

All of the CBAs we have carried out have a positive long-run net present social value (NPSV). This demonstrates that these activities are all expected to produce benefits to society that justify their costs.

The magnitude of these benefits varies substantially from activity to activity. This is unsurprising: given the very varied nature of these activities, they will be associated with a different achievable level of total benefits. Through the use of the framework we have developed, SPEN will be better able to maximise the benefits of any given activity.

While we understand that other DSOs may be producing similar figures, comparison of NPSV between DSOs are unlikely to be meaningful. This is for two reasons:

- Different DSOs are in very different situations: The best achievable NPSV will depend on highly localised factors such as the presence and cost of flexibility, the rate of demand growth etc, which require a highly complex benchmarking process to control for.
- Second, different DSOs are also likely to have adopted very different approaches to quantifying the benefits of their activities, which may produce inconsistent results. The DSO Collaborative Appendix, while helpful in setting out common principles, does not mandate an approach to calculation (which is planned for next year's submission). Some areas where DSOs' calculations may differ are noted in Table 1.

Table 1 Potential areas for differences in approach

Approach adopted here	Potential alternative approach by other DNOs
Calculate net benefits of activities (i.e. subtracting costs)	Calculate gross benefits of activities (i.e. do not subtract costs)
Avoid double-counting 'multi-stage' activities (e.g. both contracting and connecting for new flexible connections)	Count different stages of the same activity, leading to double-counting
Focus on resource costs, excluding transfers which do not benefit society as a whole	Include transfers (e.g. consider Flexibility Service Provider revenue or profit as a benefit), leading to double-counting
Only count activities undertaken this year	Include activities that have occurred in the past or may occur in future – over time with multiple submissions this would lead to double-counting
Adopt a 'do-nothing' counterfactual, but in a way which avoids clearly unnecessary costs (such as those that would be incurred if use of flexibility at a site were suddenly to cease)	Use different counterfactuals, which inflate benefits (e.g. if the counterfactual assumed a sudden cessation of flexibility without reinforcement being possible, which led to asset failure)
Only monetise carbon reductions where these are not already implicit in system operating costs monetised elsewhere	Monetise all carbon reductions, even where they are counted elsewhere, leading to double-counting
Value deferred reinforcement using the CEM approach (i.e. the time value of money of deferral)	Value deferred reinforcement based on the gross value of reinforcement avoided in a given year

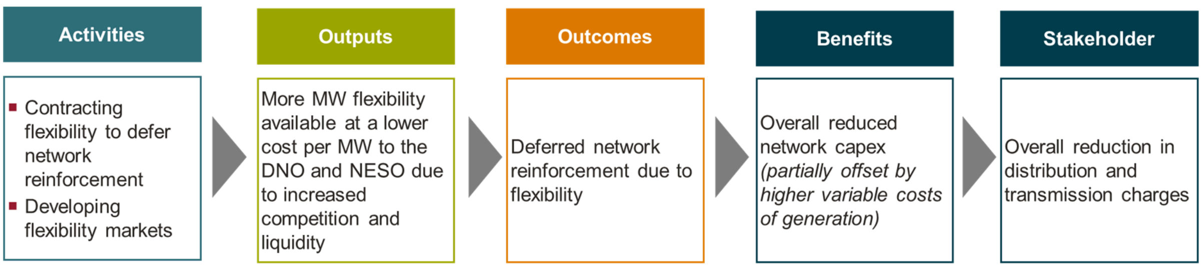
The remainder of this Executive Summary provides a brief overview of the theory of change and CBA results for each of the five groups of activities.

Helping customers to participate in a flexible energy system

This group of activities is aimed at increasing participation in flexibility markets, as well as the strategic use of that flexibility to defer reinforcement needs (the use of flexibility for operational purposes is covered in the final activity group).

Figure 1 below shows a high-level summary of the logic model for this group of activities, showing how they lead to societal benefits, which ultimately feed through to customers.

Figure 1 Summary logic model



Source: Frontier Economics

We have carried out a quantitative CBA for two activities within this group:

- **Activity 1: Contracting flexibility for network reinforcement deferral**. We have considered all areas where flexibility was successfully contracted *for the first time* during 2024/25 (our calculation excludes areas where flexibility was first successfully contracted in previous years). Compared to a counterfactual where this flexibility was not procured, we have estimated a long-run NPSV of £3.9m. This is driven by the benefits of reinforcement deferral, less the costs of flexibility.

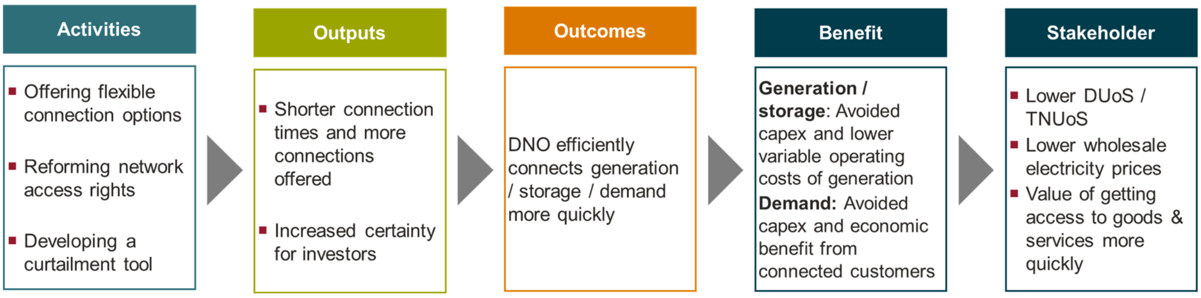
- **Activity 2: Developing markets for flexibility at the distribution level**. We have made an illustrative assumption that the market development activities carried out this year could reduce the future costs of flexibility by 1%. Under this assumption, the *gross* present value of this activity would be £2.4m. However these benefits should *not* be added to the combined total, as these savings will ultimately manifest in greater benefits for the use of flexibility being measured in future years.

Enabling capacity for customer connections, growth, and decarbonisation (part 1 – activities relating to flexible connections)

This group of activities covers activities which help more customers connect through the use of flexible connections facilitated by schemes such as Technical Limits and Load Management Schemes (LMS).

Figure 2 below shows a high-level summary of the logic model for this group of activities, showing how they lead to societal benefits, which ultimately feed through to customers.

Figure 2 Summary logic model



Source: Frontier Economics

We have carried out a quantitative CBA for two activities within this group, considered together:

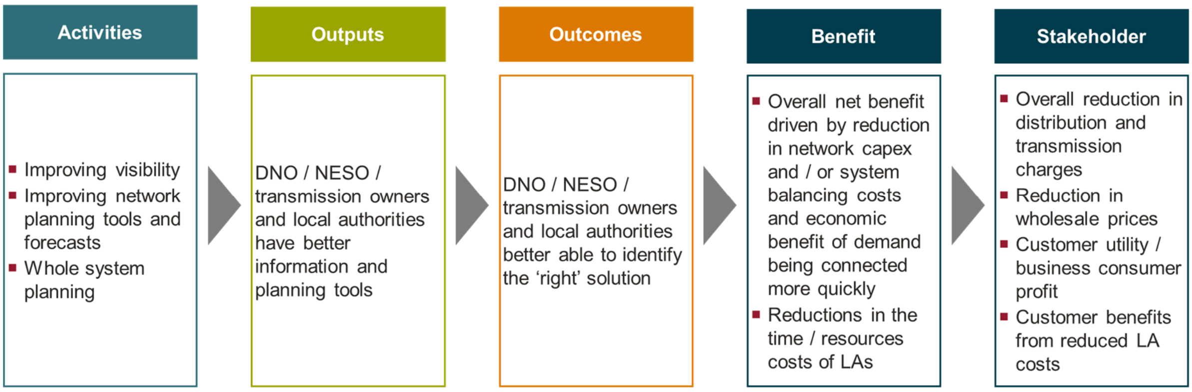
- **Activities 4 & 5: Offering flexible connections through LMS / Technical Limits, and reformed storage access rights**. We have used SPEN's data on the flexible connections contracted during 2024/25, and its best view of connection timelines and reinforcement costs were a firm connection to have been used instead. We calculate a NPSV of £542m, driven by reduced wholesale generation costs (as more efficient generation and storage assets are brought onto the system sooner) as well as reduced network reinforcement costs. We additionally estimate that SPEN's activities to bring forward demand connections could have unlocked up to £1,526m worth of additional gross value added (GVA) – although as described below this measure is subject to considerable uncertainty.

Enabling capacity for customer connections, growth, and decarbonisation (part 2 – other activities)

This group of activities covers improvements to network planning and visibility which help get more capacity out of the current network

Figure 3 below shows a high-level summary of the logic model for this group of activities, showing how they lead to societal benefits, which ultimately feed through to customers.

Figure 3 Summary logic model



Source: Frontier Economics

We have carried out a quantitative CBA for two activities within this group:

- **Activity 8: Rolling out LV network monitors to get extra capacity out of existing assets**. We have used SPEN's estimates on the amount of effective capacity unlocked by LV monitors to value the benefits associated with deferred reinforcement. When considering just those monitors installed during 2024/25 (and netting off the associated costs), this results in an NPSV of £9.4m.

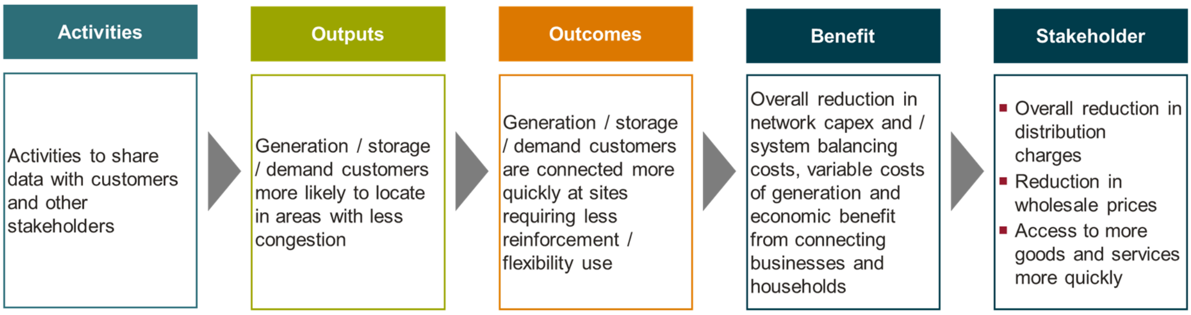
- **Activity 12**: **Strategic optimisation team activities**. This team engages with local authorities and other key regional stakeholders to understand and help develop their decarbonisation plans and ensure that these are incorporated within network plans. We have estimated that the efficiencies of carrying out this activity within SPEN (rather than local authorities) could correspond to £1.3m of net benefits this year. Note that there may be additional benefits (in terms of reduced reinforcement costs or faster connections) which we have not quantified.

Providing easy access to accurate and timely data

This group of activities covers a variety of information sharing activities to help reduce whole system costs.

Figure 4 below shows a high-level summary of the logic model for this group of activities, showing how they lead to societal benefits, which ultimately feed through to customers.

Figure 4 Summary logic model



Source: Frontier Economics

As illustrated above, effective sharing of datasets should unlock a variety of benefits, as organisations like local authorities, or potential investors in generation, storage and demand assets, can better account for congestion on the network, ultimately leading to a combination of lower reinforcement costs and/or faster connection times.

It is difficult to carry out a CBA for these activities as this would require a quantitative understanding of how these types of organisations are using DNO data in their decision-making. Nevertheless, the KPIs provided by SPEN demonstrate the reach of these activities:

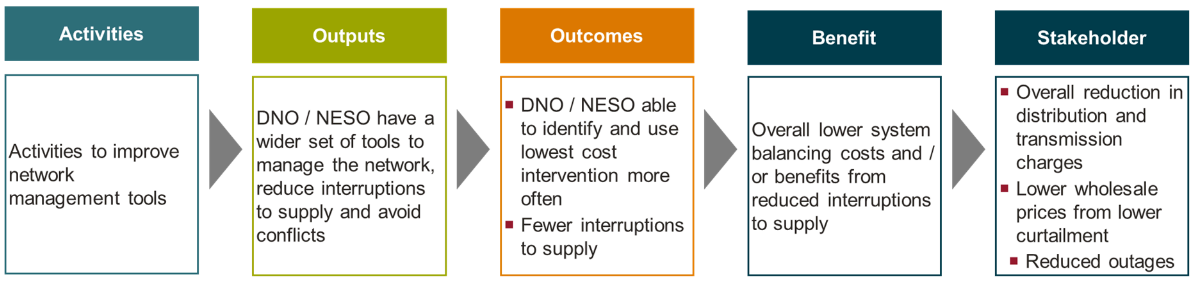
- In 2024/25, there were 2,234 registered users of SPEN's Open Data Portal.
- The vast majority of these users (1,841) actively used to the Portal to search for data, resulting in 34,000 downloads.
- In response to stakeholder feedback from the 2024 DSO Event, SPEN leveraged analytics from the Open Data Portal to create feature pages. These allow users to explore visualisations of data without needing to download or conduct their own analysis. So far, 274 users have accessed these pages.
- The 'validity' of the data (whether the values are in a correct range or format) has also improved from 48% in 2023/24 to 84% this regulatory year.

Operating a reliable and decarbonised network

These activities relate to improvements in the day-to-day operation of the network (for example identifying and responding to faults in order to reduce outages).

Figure 5 below shows a high-level summary of the logic model for this group of activities, showing how they lead to societal benefits, which ultimately feed through to customers.

Figure 5 Summary logic model



Source: Frontier Economics

We have carried out a quantitative CBA for three activities within this group:

- **Activity 17: Using flexibility to manage planned outages**. Flexibility can act as a form of insurance, mitigating the impact of an unplanned outage during an existing planned outage which would otherwise result in a loss of supply. Using Ofgem's valuations for a loss of supply, we estimate the NPSV of this activity at £4.4m.

- **Activity 18**: **Using flexibility to manage unplanned outages**. Flexibility can help mitigate the impact of unplanned outages resulting from events such as storms. SPEN procured availability from Rheidol hydro power station, which was then utilised during Storm Darragh to enable restoration of power four hours earlier for 15,000 customers. Using a similar calculation to the one above, we estimate the NPSV of this activity at £2.1m.

- **Activity 20: Improving monitoring and control of the LV network**. LV monitors can identify faults before they happen, leading to reduced outages. We estimate that, over their lifetime, the LV monitors installed during 2024/25 will be associated with a NPSV of £0.5m with regards to this benefit.

Summary of CBA results

Table 2 summarises the results of the CBAs we have carried out for SPEN's DSO activity during 2024/25. **In total, we estimate that these activities are associated with a net social present value of £563m**.

The vast majority of this benefit (about 96% of the total) relates to the benefits of using flexible connections to accelerate the connection of generation and storage to the system. Intuitively, the costs associated with generating electricity are far higher than DNO reinforcement costs, or the inconvenience associated with the relatively low levels of outages that customers experience. While all these DSO activities have value, those that facilitate the efficient operation of the wider system have the most significant effects.

Table 2 Overview of CBA results

Activity		NPSV of this year's activities
4 & 5	Offering flexible connections (excluding GVA of accelerated demand)	£542m
8	Rolling out LV network monitors to get extra capacity out of existing assets	£9.4m
17	Using flexibility to manage planned outages	£4.4m
1	Contracting flexibility for reinforcement deferral	£3.9m
18	Using flexibility to manage unplanned outages	£2.1m
12	Strategic Optimisation Team activities	£1.3m
20	Improving monitoring and control of the LV network	£0.5m
	Total quantified benefit	**£563m**
4 & 5	*Offering flexible connections (GVA of accelerated demand)*	*£1,526m*
2	*Developing markets for flexibility at the distribution level*	*£2.4m*

Source: Frontier Economics

Note: Figures in 2024/25 prices. Figures are rounded so the actual total (as presented) differs slightly from the value if the NPSVs above are summed.

Of this £563m, £51m relates to benefits and costs realised during 2024/25 and the remaining years of RIIO-ED2 – with £10m of this being realised during 2024/25 itself.

Our CBAs have quantified two additional societal benefits which are not included in this total:

- The benefits of using flexible connections to bring forward demand connections has been valued at a NPSV of £1,526m. This is an estimate of the gross value added (GVA) unlocked as a result of these activities. However considerable caution should be exercised when interpreting GVA estimate, as it assumes that, absent the accelerated connection, the resources used by businesses subject to a connection delay could not be used productively elsewhere (e.g. connecting somewhere else).

- The benefits of developing markets for flexibility at the distribution level (activity 2) were illustratively valued at £2.4m. We have not included these in the total to avoid double-counting, since these benefits will ultimately manifest in greater net benefits when flexibility is procured in future (which will be quantified in future years). However this demonstrates the value of groundwork being undertaken now.

Considerable additional value is likely to come from other activities which we have not been able to quantify (but which have a clear link to benefits, articulated through the theory of change). These include:

- Supporting distribution customers to participate in flexibility markets at the transmission level;
- development of 'Constraint Identification and Curtailment Analysis' tool;
- the use of smart meter data to get extra capacity out of existing assets;
- enhancing transformer monitoring through environmental sensors;
- improving network planning tools;
- developing and improving the accuracy of DFES forecasts;
- whole system planning activities;
- sharing data with stakeholders;
- improving the accessibility and reach of shared data;
- improving the quality of SPEN’s data;
- enhanced forecasting and modelling of curtailment requirements;
- improving real-time communications between the DNO and NESO / TSO; and
- developing an energy management platform

2 Introduction

2.1 Purpose of this work

The energy system is undergoing significant change. The transition to a zero-carbon economy requires electrifying a large proportion of transport and building heating, significantly increasing the levels of demand and generation that need to be connected to the electricity distribution network. Growing reliance on renewable energy sources like wind and solar power also creates new challenges for grid management to balance intermittent energy sources. In addition, the rise of electric vehicles (EVs) and the increasing use of distributed energy resources (DERs) such as home solar panels, battery storage, and demand-side response technologies mean that managing the distribution network is becoming increasingly complex.

The DSO role

This changing environment has required that network operators move from a traditional Distribution Network Operator ('DNO') role, which primarily focused on maintaining and upgrading infrastructure, to a more proactive Distribution System Operator 'DSO' role, where the focus expands to coordinating, optimizing, and integrating these diverse energy resources to ensure a stable, efficient, and sustainable energy supply. We summarise below Ofgem's expectations (referred to by Ofgem as its 'baseline expectations') of the roles and activities of a DSO in RIIO-ED2 (Figure 6). Throughout this document, in line with Ofgem's convention in its DSO Incentive document, we refer to SPEN as a 'DNO', but refer to the activities relevant for the SPEN's DSO role as 'DSO activities'.

Figure 6 Ofgem's baseline expecations of the DSO role

Role 1: Planning and network development	**Activity 1.1:** Plan efficiently in the context of uncertainty, taking account of whole system outcomes and promote planning data availability
Role 2: Network operation	**Activity 2.1:** Promote operational network visibility and data availability
	Activity 2.2: Facilitate efficient dispatch of distribution flexibility services
Role 3: Market development	**Activity 3.1:** Provide accurate, user-friendly and comprehensive market information
	Activity 3.1: Embed simple, fair and transparent rules and processes for procuring distribution flexibility services

Source: Based on Ofgem (June 2022), RIIO-ED2 Business Plan Guidance, Appendix 4.

The RIIO-ED2 price control arrangements includes mechanisms to facilitate the delivery of these DSO functions. For RIIO-ED2, Ofgem introduced a new Distribution System Operator incentive "*to drive DNOs to more efficiently develop and use their network, taking into account* *flexible alternatives to network reinforcement*."[1] The DSO incentive specifies annual financial rewards and penalties accruing to the DNOs based on their performance in delivery of DSO activities. This performance is assessed annually through: i) a stakeholder satisfaction survey; and ii) an evaluation by a Performance Panel assessment.[2]

The DSO Performance Panel Assessment

The performance panel assessment requires each DNO to prepare and submit an annual DSO Performance Panel submission explaining how assessment criteria have been met through their activities within the previous regulatory year. The assessment criteria are based on the requirements set out in Ofgem's baseline expectations of the DSO role. We reproduce the assessment criteria set out by Ofgem below.

Table 3 DSO Performance Panel assessment criteria

DSO Performance Panel assessment criterion	Weighting
Delivery of DSO benefits	30%
Data and information provision	20%
Flexibility market development	20%
Options assessment and conflict of interest mitigation	20%
Distributed energy resourced ('DER') dispatch decision-making framework	10%

Source: Ofgem (January 2025), Distribution System Operation Incentive Governance Document, Table 3

The results of the first DSO Performance Panel assessment were published in September 2024, for the activities undertaken in the first year of RIIO-ED2, (regulatory year 2023/24).[3] The panel highlighted that the DNOs had demonstrated strong performance in engaging with stakeholders, DSO-DNO governance, commitment to delivering a "flexibility first" strategy, transparency of decision-making and data practices and whole system thinking. The panel also found areas where DNOs could improve in the future, particularly in relation to the depth of evidence and the rigour of the quantification of benefits.[4]

1 Ofgem (November 2022), RIIO-ED2 Final Determinations – Core Methodology, p. 69.

2 The outturn performance metrics was originally introduced as a part of the financial incentive but was later changed to a reporting requirement (i.e. not associated with a financial reward / penalty).

3 Ofgem (September 2024), DSO Incentive Report 2023-24.

4 Ofgem (September 2024), DSO Incentive Report 2023-24.

Aims of this work

Ahead of its next submission to the DSO Performance Panel for the regulatory year 2024/25, SP Energy Networks (SPEN) has commissioned Frontier Economics to develop a framework for tracking benefits from its activities which SPEN can use on an enduring basis and to produce a robust quantitative benefits assessment of its DSO activities carried out in each regulatory year. Specifically, the aims of this work have been to:

- Identify the routes through which SPEN's DSO activities lead to benefits for society and customers;
- identify a set of priority benefits where quantification is feasible and develop a methodology for quantifying these benefits; and
- calculate the associated benefits for the 2024/25 regulatory year.

Our results and methodology are set out in this report and accompanying Excel models. These models are designed so that they can be updated by SPEN on an annual basis as part of its ongoing tracking of benefits over RIIO-ED2.

2.2 Structure of this report

This report is structured in the following way:

- In Section 2, we summarise our approach to the benefits assessment, including our alignment to the guidance set out by Ofgem and evaluation best practice. We also set out the activities undertaken by SPEN in the regulatory year 2024/25, which we assess in this report. SPEN has grouped their activities into four categories, which we use to organise the remainder of the report.
- In Section 3 – 7 we summarise our benefits assessment for SPEN's activities, with each chapter covering a category of SPEN's activity.

3 Our approach to assessing benefits

In this section we summarise the broad approach we have taken to assessing the benefits of SPEN's DSO activities. Our approach has been informed by the following guidance:

- **Ofgem's DSO Incentive Governance Document (updated January 2025).**[5] This document sets out the arrangements for the DSO incentive in RIIO-ED2, including the specification of the DSO's Performance Reports and how performance will be assessed by the Performance Panel. For example, Ofgem sets out requirements that companies focus on new activities or new steps to existing activities delivered within the regulatory year. [6]

- **Ofgem's DSO Incentive Report for 2023/24 (September 2024).**[7] This document sets out the performance of the companies under the DSO incentive in the first year of the RIIO-ED2. This includes feedback from the DSO Performance Panel and guidance for the next annual DSO submission.

- **The DSO Collaboration Panel's Common Appendix (April 2025).**[8] This is a common appendix, co-drafted by all DNOs, which sets out common principles for the articulation and categorisation of benefits, as well as common terminology. We refer to this as the 'common appendix' throughout this document.

- **HM Treasury's Green Book (2022).**[9] Ofgem's DSO Incentive Governance Document states that the quantification of benefits should be consistent with established methods for economic appraisal such as the HMT Green Book.[10]

- **HM Treasury's Magenta Book (2020).**[11] This sets out the Theory of Change approach used in this report.

- **Existing sector-specific appraisal tools** such as Ofgem's standard RIIO-ED2 cost-benefit analysis framework,[12] and the ENA's Common Evaluation Methodology used by networks to assess opportunities for flexibility.

Informed by this guidance, our approach is structured around three stages:

---

5 Ofgem (January 2025), Distribution System Operation Incentive Governance Document.

6 Ofgem (January 2025), Distribution System Operation Incentive Governance Document, paragraph 4.15.

7 Ofgem (September 2024), DSO Incentive Report 2023-24.

8 ENA (April 2025), Common appendix and glossary to DSO performance panel submissions

9 HM Treasury (2022), The Green Book.

10 Ofgem (January 2025), Distribution System Operation Incentive Governance Document, Appendix 5, criteria relating to Delivery of DSO benefits

11 HM Treasury (2020), The Magenta Book.

12 Ofgem (October 2021), RIIO-ED2 Data Templates and Associated Instructions and Guidance

- identifying the relevant DSO activities;
- developing a logic model to show the chain of causality from activities to outcomes; and
- developing and then implementing quantification methodologies for each priority benefit.

We discuss each step in turn below.

3.1 Identifying the relevant DSO activities to assess

The first step is to identify and define the relevant DSO activities that should be assessed. SPEN has provided us with a list of its DSO activities in the regulatory year 2024/25. These activities have been divided into four broad groups, the categorisation of which took into account input from SPEN's Independent Net Zero Advisory Council (INZAC). This categorisation has helped avoid double-counting, as well as facilitating the creation of a high-level Theory of Change for each activity group which may be more accessible to stakeholders than the more detailed versions. The groups are:

- **Helping customers to participate in a flexible energy system**. This covers activities aimed at increasing participation in flexibility markets, as well as the use of that flexibility to defer reinforcement needs (the use of flexibility for operational purposes is covered in the final activity group).
- **Enabling capacity for customer connections, growth, and decarbonisation**. This covers activities which provide the network capacity needed for customer connections and societal growth. Given the breadth of these activities, we have considered them in two parts:
  - First, the use of flexible connections; and
  - second, activities that improve the network planning process and outcomes by improving decision making, getting more capacity out of the existing network, working with key regional stakeholders, and developing whole system solutions.
- **Providing easy access to accurate and timely data**. This captures a variety of information sharing activities to help reduce whole system costs.
- **Operating a reliable and decarbonised network**. These activities relate to improvements in the day-to-day operation of the network (for example identifying and responding to faults in order to reduce outages).

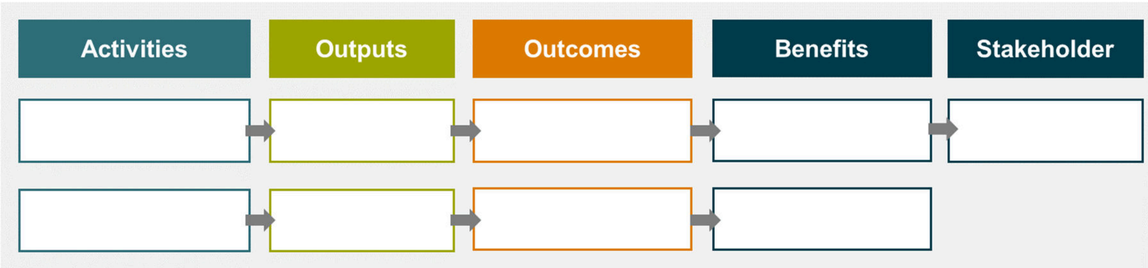
Each chapter of this report focusses on one of these activity groups. The activities within each group are identified, and mapped to Ofgem's DSO baseline expectations to demonstrate how these are DSO-specific activities.

3.2 Developing logic models to link activities to benefits

These activities are not valuable in and of themselves, but because of the benefits that they ultimately deliver.

For each activity group set out in the previous section, we articulate the theory of change that links DSO activities to benefits. This is shown graphically through a logic model (a tool recommended as best practice in the HM Treasury Magenta Book as well as the Common Appendix). Figure 7 below shows a high-level logic model framework, using the common format set out in the DSO Collaboration Panel's Common Appendix.

Figure 7 Logic model framework



Activities relate to the programmes, tasks or actions done by SPEN. For example, this could include running flexibility tenders.

Outputs are the immediate and are observable effects of the activities. For example, running flexibility tenders would lead to increased volumes of flexibility contracted by the DNO. Note that the Common Appendix groups outputs together with outcomes: We have made this additional distinction to make the chain of causality clearer.

Outcomes are the changes that result from these outputs. For example, increased volumes of flexibility may result in deferred network reinforcement.

Benefits are the long-term societal benefits results (both intended and unintended) which follow from the outcomes identified. For example, deferred network reinforcement ultimately means lower network capital expenditure (due to the time value of money).[13] These benefits include both:

[13] This stage of a logic model is more typically termed 'Impacts', as the overall results of an activity may be to impose a cost rather than a benefit. We have adopted the terminology agreed in the Common Appendix, however our use of the term 'benefit' does not presuppose that every action will have a net benefit rather than a cost.

- Direct benefits which the Common Appendix defines as those ‘directly attributable’ to an activity. In practice, these will typically be changes to a DNO’s own costs such as for reinforcement.

- Indirect benefits, which the Common Appendix defines as ‘secondary effects’ or benefits to ‘wider society’.

Public sector appraisal, as set out in the HMT Green Book, is focused on the appraisal of whole societal resource costs, and does not concern itself with the lower level ‘transfers’ between parties (i.e. where benefits flow to one individual economic actor at the expense of another, such that the ‘net’ societal impact is the same). We explain in section 3.3.1 how quantifying transfers could lead to double-counting of benefits.

However, we are cognisant of Ofgem’s statutory duties to protect the interests of existing and future electricity consumers and the purpose of the DSO incentive to maximise benefits for electricity consumers. In addition to identifying societal impacts, we therefore also separately identify the **stakeholder benefits** that show how the benefits ultimately flow through to stakeholders. In the vast majority of cases, the ultimate beneficiaries will be consumers, and where possible we will quantify the impact on consumer bills.

3.3 Developing quantification methodologies for each benefit

The extent to which we are able to carry out a full quantification of the benefits of each activity depends on the data that are currently available:

- **Quantified benefit:** Where it is has been feasible, we quantify the expected benefits of an activity using a cost-benefit analysis (CBA). This is described below. The CBA has been implemented in a series of spreadsheets which have been shared with SPEN and can be used going forward (both to prepare for future DSO performance panel submissions, but more importantly to help prioritise work to maximise value).

- **Quantitative KPI:** In some cases, while it has been difficult to carry out a full CBA, data is available to quantify the activities, outputs, or outcomes that should lead to these benefits. These are presented as quantitative KPIs.

- **Qualitative link to benefits**: For some activities, there is no clear quantitative measure that could be used as a KPI. In these cases we are still able to provide a qualitative link to benefits, through the theory of change described above. This demonstrates that there is a reasonable channel through which the activity could lead to benefits, and to whom these benefits will accrue. It also provides a framework that could be used to carry out further quantification in future.

A summary of the list of activities and our assessment approach is set out in Table 4 below. This is a high-level list and many activities are made up of several sub-activities, described in the relevant sections of this report.

Table 4 SPEN's 2024/25 activities

#	Activity	Qualitative link to benefits	Quantitative KPI	Quantified benefit
Helping customers to participate in a flexible energy system				
1	Contracting flexibility for reinforcement deferral	✓	✓	✓
2	Developing markets for flexibility at the distribution level	✓	✓	✓
3	Supporting distribution-connected flexibility to provide services to the NESO	✓	×	×
Enabling capacity for customer connections, growth, and decarbonisation				
Part 1				
4	Offering flexible generation / demand connections through LMS and Technical Limits to manage *transmission* constraints[14]	✓	✓	✓
5	Offering flexible connections under reformed network access storage rights for storage	✓	✓	✓
6	Offering flexible generation / demand connections under other schemes to manage *distribution* constraints	✓	✓	✓
7	Developing a connections analytical tool to improve accuracy of curtailment forecasts	✓	×	×
Part 2				
8	Rolling out LV network monitoring and using LV network monitoring and smart meter data to improve network visibility	✓	✓	✓
9	Installing primary transformer environmental sensors	✓	✓	×
10	Improving network planning tools	✓	×	×
11	Developing and publishing DFES forecasts	✓	✓	×
12	Strategic Optimisation team activities	✓	✓	✓
13	Whole system planning activities	✓	×	×

[14] Technical limits in SPM applies to generation; LMS in SPD applies to demand and generation.

#	Activity	Qualitative link to benefits	Quantitative KPI	Quantified benefit
	Providing easy access to accurate and timely data			
14	Sharing data with stakeholders	✓	×	×
15	Improving accessibility and reach of data	✓	✓	×
16	Improving the quality of data	✓	✓	×
	Operating a reliable and decarbonised network			
17	Using flexibility to manage planned outages	✓	✓	✓
18	Using flexibility to manage unplanned outages during Storm Darragh	✓	✓	✓
19	Enhanced forecasting and modelling of curtailment requirements	✓	×	×
20	Improved monitoring and control of the HV/LV network	✓	✓	✓
21	Improving real-time communications and data exchange between DNO and NESO / TSO	✓	×	×
22	Developing an energy management platform	✓	×	×

Source: SPEN

3.3.1 General approach to quantification

The key aim of the quantification is to produce a Green Book-style CBA showing the Net Present Social Value (NPSV) of all DSO activities that SPEN has carried out in the 2024/25 regulatory year. The exact methodology used to calculate the NPSV varies from activity to activity, but can be summarised as:

- Define the DSO activities to be assessed, and the relevant counterfactual against which to assess them;
- calculate the expected societal *benefits* resulting from these activities;
- calculate the expected societal *costs* resulting from these activities;
- discount and sum the costs and benefits to produce a NPSV.

Defining activities and counterfactual

It is crucial that the CBA only considers the impact of *new* activities (or improvements to existing activities) undertaken in the current regulatory year. This is aligned to Ofgem's guidance which states that '*The DSO Performance Panel will be asked only to take account of evidence if it relates to new activities delivered by the distribution network companies to improve performance within that Regulatory Year …[or] .implementing additional steps to go* *above and beyond expectations in pre-existing activities.*'[15] It is also important to ensure no double-counting: the costs and benefits quantified in any one DSO Performance Panel submission should not duplicate those that will be reported in the submission for a different year.

This is a particularly crucial issue for 'multi-stage' activities where a variety of activities are required, potentially in different years, to unlock a benefit. For example, setting up new flexible connections involves:

- designing connection offers;
- providing connections offers ('quoting');
- contracting with customers (i.e. when customer accepts the connection offer);
- beginning the construction work to enable connection; and
- completing the work to enable the connection ('energisation' or point of 'connection').

If each of these were considered separately as an 'activity' then there would be significant double-counting (e.g. connections designed this year might be contracted in a subsequent year, and completed in yet another year). We therefore identify a single stage of the activity on which to focus, and use this to consistently define 'this year's' activities.

Costs and benefits can only be quantified in relation to a counterfactual. Given the purpose of the quantification is to estimate the overall benefits of DSO activity, we have generally adopted a 'do nothing' counterfactual where no new or further DSO-related activity would have been undertaken in 2024/25. In some cases, entirely ceasing DSO activities would lead to unrealistically high costs that a DNO would never choose to incur. For example, consider an area where a DNO has previously procured flexibility to defer reinforcement. Suddenly stopping the dispatch of flexibility could lead to network assets exceeding their headroom (with potential high costs due to failure). Where relevant, we have therefore specified a counterfactual to avoid these types of cost, so as to not over-estimate the benefits of DSO activities.

Estimating societal benefits

We have carried out modelling to estimate the benefits that can be attributed to the activity when compared to the counterfactual, on a year-by-year basis.

Our focus is on societal resource costs. Importantly, this excludes transfers which are defined by the Green Book as '*pass[ing] purchasing power from one person to another and do not involve the consumption of resources. Transfers benefit the recipient and are a cost to the donor and therefore do not make society as a whole better or worse off*'. Excluding transfers

[15] Ofgem (January 2025), Distribution System Operation Incentive Governance Document, paragraph 4.15. See also Ofgem (September 2024), DSO Incentive Report 2023-24, page 19, which states that "*What has been achieved in the discussed year (whether it's completely new activities or new steps to existing activities) and the resultant benefits should be clearly demonstrated in that year's submission*".

ensures we focus on the ultimate beneficiaries of benefits, and avoid double-counting when one stakeholder group may pass on benefits to another. This is also consistent with the Common Appendix which states '*Total NPSV figures should not include transfers of resources between stakeholder groups*'.[16]

For example, consider any activity which leads to the procurement of flexibility. In the short term, this represents revenue for a Flexibility Service Provider, and so might be seen as a benefit to that stakeholder group. However, by itself, it is just a transfer of money from the DNO (and ultimately from the DNO's customers) to the flexibility provider, and so it would not add to NPSV. In order to calculate the NPSV impact of procuring flexibility, a DNO would instead need to consider the underlying resource costs, such as the benefits of deferred reinforcement.

The source of these benefits is varied, but includes:

- **DNO (or transmission network) avoided reinforcement costs**. Typically, DSO activities will defer reinforcement, but not remove the need for it entirely. The time value of money means that there is still a value to this deferral (albeit generally much less than the total cost of reinforcement that is being deferred), and we use the same methodology as the Common Evaluation Methodology (CEM) to calculate this.

- **System operating costs**. Activities that change the dispatch of generation, storage, or other flexible technologies will affect the overall costs of supplying electricity to the country (such as fuel and variable operating and maintenance costs).

- **Carbon emissions**. These are valued using the standard DESNZ appraisal values.[17] In many cases, carbon emissions will already be 'internalised' in other elements of the calculation (for example, electricity wholesale prices will account for the impact of ETS payments) and so we only value carbon emissions when these are not captured elsewhere.

- **Reductions in outages for customers**. In line with Ofgem's CBA guidance, we value these using the CML and CI rates in the RIIO-ED2 templates.[18] Importantly, we are using these rates as proxies for the welfare loss caused by interruptions, rather than the incentive payments under RIIO (which are a transfer).

In some cases, multiple activities may contribute to the same benefit. For example, 'running flexibility auctions' is an activity that may lead to reduced reinforcement costs. However this is also facilitated by 'developing the market for flexibility'. In such cases we allocate the benefits (and costs) in a way which avoids double-counting. For example, in this particular example,

16 ENA (April 2025), Common appendix and glossary to DSO performance panel submissions

17 Activities that change the dispatch of generation may also have an effect on air quality. For example, connecting renewables to the network sooner may displace fossil fuel plants (reducing air pollution), while the use of fossil fuel generation for flexibility could increase air pollution. We do not quantify these effects.

18 https://www.ofgem.gov.uk/publications/riio-2-final-data-templates-and-associated-instructions-and-guidance

our headline benefits exclude the benefits of ‘developing the market for flexibility’ as, in the long-run, the methodology used to estimate benefits for ‘running flexibility auctions’ will capture all the relevant benefits.

Estimating societal costs

The “Net” in NPSV relates to showing benefits net of costs, rather than simply presenting benefits. Carrying out a cost-benefit analysis without any consideration of costs would not enable any meaningful assessment of whether an activity is valuable. For example, consider the activity of procuring flexibility to defer reinforcement, where the main benefits relate to the time value of money in deferring reinforcement, and the costs are the costs of procuring flexibility (which might relate e.g. to the fuel used in backup generators). If only the benefits were considered, then it would seem optimal to procure as much flexibility as is possible, even though the costs of doing so could outweigh the benefits.

Discounting and summing

In line with the Green Book, the benefits and costs for each year are netted off against one another, and then discounted back to today using the standard 3.5% social discount rate. We present all benefits in 2024/25 prices.[19]

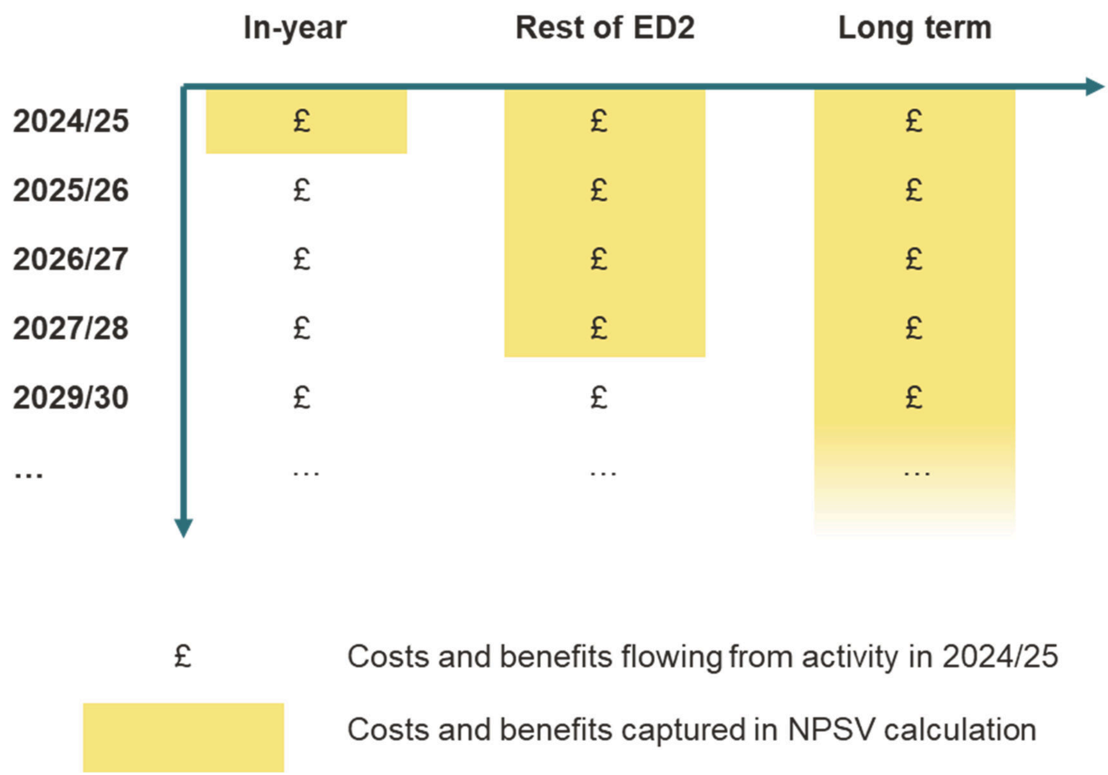
The most important output from this process is the long-term NPSV, which considers all of the costs and benefits of this year’s activities, regardless of when they occur.

The DSO Performance Panel assessment guidance also indicates that DNOs should articulate ‘…*actual benefits the distribution network company has realised within the RIIO-ED2 period*…’, and last year’s DSO Incentive Report stated that ‘*substantive evidence was rarely given to show what benefits have been realised in the current year*.’ To meet these requirements, we have also carried out CBA calculations which only consider costs and benefits falling within 2024/25, or within the rest of RIIO-ED2. Figure 8 below illustrates how the three calculations we present truncate the NPSV at different points.

However, we would suggest caution when interpreting these figures: In many cases, DSO activities require up-front investments which will lead to benefits over many future years. Truncating the CBA to look at costs in a number of early years may make some activities appear to be value-destructive when they are otherwise an efficient use of resources. For example, an investment like LV monitoring may only pay off over several years. In other cases, truncating the CBA may lead to over-estimating net benefits. For example, if reinforcement is deferred from within RIIO-ED2 to RIIO-ED3, then a CBA only including the former period may make it appear that the reinforcement spend has been removed altogether.

19 Adjustments to price base are made using a combined RPI-CPIH inflation index in accordance with the methodology applied in Ofgem’s RIIO-ED2 Data Templates (see Ofgem, October 2021, RIIO-ED2 Business Plan Data Templates). As CPIH-based forecasts are not reliably available, we use the consumer prices index (CPI) as a proxy for CPIH as per Ofgem's guidance (see Ofgem, October 2021, RIIO-ED2 Data Templates and Associated Instructions and Guidance).

Figure 8 Illustration of how we report NPSV for different periods



Source: Frontier Economics

Calculating a bill impact

For some activities, the key costs and benefits would all be expected to ultimately flow through to customers through the DUoS element of the bill. For example, the use of flexibility to defer distribution reinforcement leads to costs (in the form of paying for flexibility services) and benefits (through deferred reinforcement) which are initially received by SPEN, and in the long-term would be expected to flow through to its customers. For these 'direct' benefits, we have calculated a representative impact on customer bills.

This impact is calculated by determining the net present value of benefits as a percentage of SPEN's total allowed revenue for 2024/25, and then applying this percentage to a typical domestic DUoS bill. This provides an illustrative estimate of the saving in bills from this year's activities, if it were hypothetically to be passed through to customers in one lump sum. This figure should be seen as giving an 'order of magnitude' estimate of how savings might ultimately affect a typical customer: In practice, the DNO regulatory regime is far more complex and so savings will be passed through over a longer period (and the benefits of some gains in efficiency may, at least in the first instance, be shared between the DNO's customers and its shareholders).

We have not calculated bill impacts for activities where key benefits are not passed through DUoS. For example, this includes activities where customers benefit from a reduction in interruptions, or from the reductions in wholesale energy cost which ultimately arise from bringing forward generation connections. This is to avoid presenting what could be a misleading figure that only includes some costs and benefits but not others.

3.3.2 Interpreting the results

The CBA framework described in this report (and implemented in spreadsheet models provided to SPEN) has been designed to support the submission of benefit figures for this and future years' DSO Performance Panel submission. However, more importantly, it can be used as tool to help SPEN continue to refine its DSO activities so that they provide greatest value for money to customers.

This section briefly describes some ways in which the framework and its results can be used – as well as areas where more caution is required.

The most important outputs are the long-run NPSVs for each activity. These figures provide the best view of the overall social value of each activity undertaken this year. If positive, then it demonstrates that the activity is likely to be providing worthwhile benefits. If negative, then it is a warning sign that the activity may not be providing value-for-money. This would suggest a need for further investigations to determine why this is the case (e.g. is the activity laying the groundwork for future high-value activities that we have not been able to capture), and ultimately whether the activity needs to be modified or ceased altogether.

The *sign* of the figures is likely to provide more information than their overall magnitude. The activities are all extremely different, and so there is no reason to suppose that the achievable benefits from one activity will be of the same order of magnitude as another. In general, any activity with a positive NPSV should be seen as worthwhile. That said, if an activity has an extremely low positive NPSV, it may be worth considering whether there are costs which are not justified, or whether there are further opportunities to make use of its outputs.

The CBA framework can be used to guide SPEN's DSO activities going forwards. By inputting plans for future activities, the framework we have developed can be used to refine SPEN's DSO activities so that they deliver the greatest value. For example, SPEN could populate the CBA with details of its planned LV monitoring rollout to determine the NPSV of next year's activities – and carry out sensitivities to see how this can be maximised.

SPEN already carries out a considerable amount of investment appraisal activity in this way. For example, the CEM is used determine whether it is worthwhile going ahead with a particular flexibility scheme, and other CBAs underlie important decisions such as the roll-out of LV monitoring. The framework developed here can help build on this work.

Comparisons across time may be helpful – but must be interpreted with caution. The spreadsheet tool we have developed has been designed to allow SPEN to compare benefits in one year with those from previous years, as well as comparing KPIs. Such comparisons may be helpful to help unpick what is driving changes over time.

However it may not always be possible to obtain year-on-year increases in NPSV, as the scope of DSO activities will be limited by the external environment. For example, in most local areas, it is expected that there will be a significant growth in electricity demand (due to the roll-out of low carbon technologies) followed by a plateau as the rollout completes. In the very long-run, there are likely to be fewer opportunities to use flexibility to defer reinforcement, as local areas will have already been reinforced, or will have settled at a higher level of demand which can still be accommodated on existing assets. It is reasonable that, year-on-year, no incremental activity may be the appropriate and efficient action.

Comparisons of the total NPSV of activities between different DNOs are even less likely to be meaningful. This is firstly because different DNOs are in very different situations: The best achievable NPSV from DSO activities will depend on highly localised factors such as the presence and cost of flexibility, the rate of demand growth etc, which would need a highly complex benchmarking process to control for.

Different DNOs are also likely to have adopted very different approaches to quantifying the benefits of their activities, which may produce inconsistent results. The DSO Collaborative Appendix, while helpful in setting out common principles, does not mandate an approach to calculation (which is planned for next year’s submission). Some areas where DNOs’ calculations may differ are noted in Table 5.

Table 5 Potential areas for differences in approach

Approach adopted here	Potential alternative approach by other DNOs
Calculate net benefits of activities (i.e. subtracting costs)	Calculate gross benefits of activities (i.e. do not subtract costs)
Avoid double-counting 'multi-stage' activities (e.g. both contracting and connecting for new flexible connections)	Count different stages of the same activity, leading to double-counting
Focus on resource costs, excluding transfers which do not benefit society as a whole	Include transfers (e.g. consider Flexibility Service Provider revenue or profit as a benefit), leading to double-counting
Only count activities undertaken this year	Include activities that have occurred in the past or may occur in future – over time with multiple submissions this would lead to double-counting
Adopt a 'do-nothing' counterfactual, but in a way which avoids clearly unnecessary costs (such as those that would be incurred if use of flexibility at a site were suddenly to cease)	Use different counterfactuals, which inflate benefits (e.g. if the counterfactual assumed a sudden cessation of flexibility without reinforcement being possible, which led to asset failure)
Only monetise carbon reductions where these are not already implicit in system operating costs monetised elsewhere	Monetise all carbon reductions, even where they are counted elsewhere, leading to double-counting
Value deferred reinforcement using the CEM approach (i.e. the time value of money of deferral)	Value deferred reinforcement based on the gross value of reinforcement avoided in a given year

4 Helping customers to participate in a flexible energy system

In this section we describe the benefits associated with SPEN's activities in regulatory year 2024/25 to help customers participate in a flexible energy system. The specific activities considered as part of this activity group are summarised in the table below.

Activity Group: Helping customers to participate in a flexible energy system				
#	**Activity**	**Qualitative link to benefits**	**Quantitative KPI**	**Quantified benefit**
1	Contracting flexibility for reinforcement deferral	✓	✓	✓
2	Developing markets for flexibility at the distribution level	✓	✓	✓
3	Supporting distribution-connected flexibility to provide services to NESO	✓	×	×

This section is structured as follows:

- In section 4.1, we describe SPEN's activities in 2024/25.
- In section 4.2, we set out the theory of change linking these activities to societal and consumer benefits.
- In section 4.3, we then set out our methodology and results for quantifying the benefits of SPEN's 2024/25 activity of contracting flexibility for reinforcement deferral.
- In section 4.4, we then set out our methodology and results for quantifying the benefits of SPEN's 2024/25 activity of developing markets for flexibility at the distribution level.

4.1 SPEN's activities in 2024/25

4.1.1 Activity 1: Contracting flexibility for network reinforcement deferral

On an ongoing basis, SPEN assesses whether different parts of its network will require reinforcement, and whether it would be cost-effective to defer this reinforcement through the use of flexibility. It then runs auctions to procure this flexibility. In 2024/25, SPEN contracted flexibility for the first time in several network areas where, ahead of ED2, flexibility had been identified in Engineering Justification Papers as a more cost-effective solution than traditional reinforcement.

This relates to activity 1.1.4 in Ofgem's baseline expectations, which states '*DNOs to have in place transparent and robust processes for identifying and assessing options to resolve* *network needs, using competition where efficient*' and '*DNOs should consider flexibility and promoting energy efficiency in addition to innovative use of existing network assets and traditional reinforcement*'.[20]

SPEN also procures flexibility for operational purposes: This activity is quantified separately in section 8.

4.1.2 Activity 2: Developing flexibility markets at the distribution network level

SPEN has carried out a wide variety of activities with the aim for increasing market liquidity in flexibility services. This increased competition will ultimately mean that more flexibility will become available over time, at a lower cost to SPEN. SPEN has indicated to us that it carried out the following activities in 2024/25:

- Removed minimum volume and technology requirements for participating in flexibility markets to increase the pool of potential providers.
- Changed from longer-term tendering to month-ahead procurement and dispatch[21].
- Incorporated and used standard industry agreed contracts and pre-qualification questionnaires[22], which should reduce complexity for potential providers participating across multiple DNOs.
- Published a market prospectus[23] that indicates SPEN's flexibility service requirements in the near term (i.e. for the next three years until 2028) and describes new flexibility products. This should help providers better understand the value of the opportunity by providing information on the size and value of the market and give greater confidence to market participants.
- Engaged with stakeholders, through:
  - Carrying out 85 bilateral surgeries and four public events;
  - participating in ENA working groups to share and mitigate blockers highlighted by SPEN stakeholders; and
  - participating in Elexon Market Facilitator stakeholder planning sessions.

20 Ofgem (2021), *RIIO-ED2 Business Plan Guidance* p77

21 SPEN (November 2024), Distribution Flexibility Service 2024/25 Market Prospectus, page 6.

22 This is the ENA v3 standard Flexibility Services Agreement. See SPEN's site here.

23 SPEN (November 2024), Distribution Flexibility Service 2024/25 Market Prospectus.

- Introduced a new minimum threshold for accepting tenders to prevent participation where this would not be viable, to avoid waste of resources and reducing confidence in the market.[24]

- Taken measures to give flexibility market participants confidence that SPEN is a neutral market facilitator. Specifically, SPEN has:

  - Created a new conflict of interest management process and published a COI Management Plan.

  - Published SPEN's DNO:DSO Operating Framework.

  - Updated SPEN's Decision Making Framework[25].

These activities correspond to aspects of Ofgem's baseline expectations, including:

- 3.1.1 – *DNOs collate and publish as much relevant data and information as reasonable that will help market participants identify and value opportunities to provide network services to DNOs and take market actions that support efficient whole system outcomes*
- 3.2.1 – *DNOs to have clear processes in place for developing and amending distribution flexibility services products, contracts, and qualification criteria, that are, wherever possible, standardised*
- 3.2.2 – *DNOs should identify the optimum combination of longer and shorter term lengths of markets and contract lengths reflecting the network need*
- 3.2.4 – *Market support services, such as pre-qualification, credit-checking and settlement must enable simple and cost-efficient participation in markets*
- 3.2.5 – *DNOs to introduce other proportionate measures, developed with robust stakeholder engagement, to identify and address actual and perceived conflicts between its DSO and network ownership roles or other business interests*

4.1.3 Activity 3: Supporting distribution customers to participate in flexibility markets at the transmission network level

In 2024/25, SPEN has engaged with NESO by holding MW Dispatch planning meetings, to increase the NESO's access to DER flexibility providers and thus help to reduce system balancing and transmission constraints. SPEN is preparing to roll this out in 2025/26. In addition, SPEN has included non-exclusivity clauses as standard in its contracts, so that providers are able to participate in NESO markets as well as SPEN-run markets.

24 Specifically SPEN does not tender for flexibility if the offered price is below the threshold of £80-£100/MW/h.

25 SPEN, Decision Making Framework March 2025

This activity corresponds to DSO baseline expectation 3.2.2, which states that '*DNOs should consider arrangements to support DERs to provide services that meet both DNO and ESO needs*'.

4.2 How these activities link to benefits

The logic model in Figure 9 below illustrates how these activities ultimately flow through to benefits for wider society and specific stakeholders.

4.2.1 Outputs

These activities above should lead to:

- **Greater volumes of flexibility available to the DNO and NESO.** Running auctions themselves will directly lead to increased volumes of flexibility being available for use by the DNO. There may also be a feedback effect, where the demonstrated ability of flexibility providers to earn a profit through these services leads to more providers entering the market. The activities to support the development of flexibility markets should reduce barriers support greater participation in auctions by existing providers, as well as encouraging new service providers to participate, in turn leading to greater volumes of flexibility available for both the DNO and NESO.

- **Reduced unit costs of flexibility services.** Increased competition and liquidity in DNO/NESO auctions from entry of new flexibility providers participating in flexibility auctions should reduce the unit costs of flexibility procured (in economic terms, the supply curve for flexibility will have shifted out). In addition, reduced investor risk may lead to more competitive bids.

4.2.2 Outcomes

Given increased volumes of flexibility at lower unit costs, the DNO and NESO should more often be able to use flexibility as a lower cost alternative to reinforcement. This leads to:

- **an increase in the network reinforcement deferred**; and

- **an increase in volumes of flexibility actually procured by the DNO / NESO**.

4.2.3 Societal benefits

The resulting societal benefit is an overall reduction in network costs (as network capital expenditure reduces by more than any increases in flexibility payments). Specifically:

- There is a time value associated with the deferral of capital expenditure (i.e. because the capital can be productively employed elsewhere in the interim). Deferred reinforcement therefore leads to **lower network capital expenditure**.

- There is also a **(partially) offsetting societal cost that arises from the use of flexibility to defer reinforcement.** This is since assets providing flexibility services incur operational costs (such as fuel, carbon, and variable O&M costs). Given the need to balance supply and demand nationally, this additional local generation will result in a generator elsewhere reducing output, creating some offsetting costs. The local generator providing flexibility is typically assumed to have higher variable costs (since it would otherwise have been in-merit and generating, and thus unable to provide flexibility). A similar effect can arise from demand shifting, for example through the use of a battery that requires energy to be shifted from one period to another. In such cases, the battery may discharge energy at a time when it is less valuable from the perspective of the wholesale market.[26]

- These costs will reduce over time due to increased participation in the market due to activities to develop competition in the market (discussed in section 4.4 below).

For larger generators, the costs described above will already include a cost associated with purchasing carbon permits on the UK ETS. However this is not the case for carbon emissions from smaller DER that fall under the threshold of current UK ETS regulations. We have therefore separately estimated the impact on **carbon emissions in the non-traded sector**. These will not be reflected directly in monetary costs or bills, but the emission of greenhouse gasses represents a cost to society as a whole.

4.2.4 Stakeholder benefits

Various stakeholder groups will be affected by these impacts, although, in the long-term, we expect the impact to be neutral as these benefits will be passed on to consumers. For example:

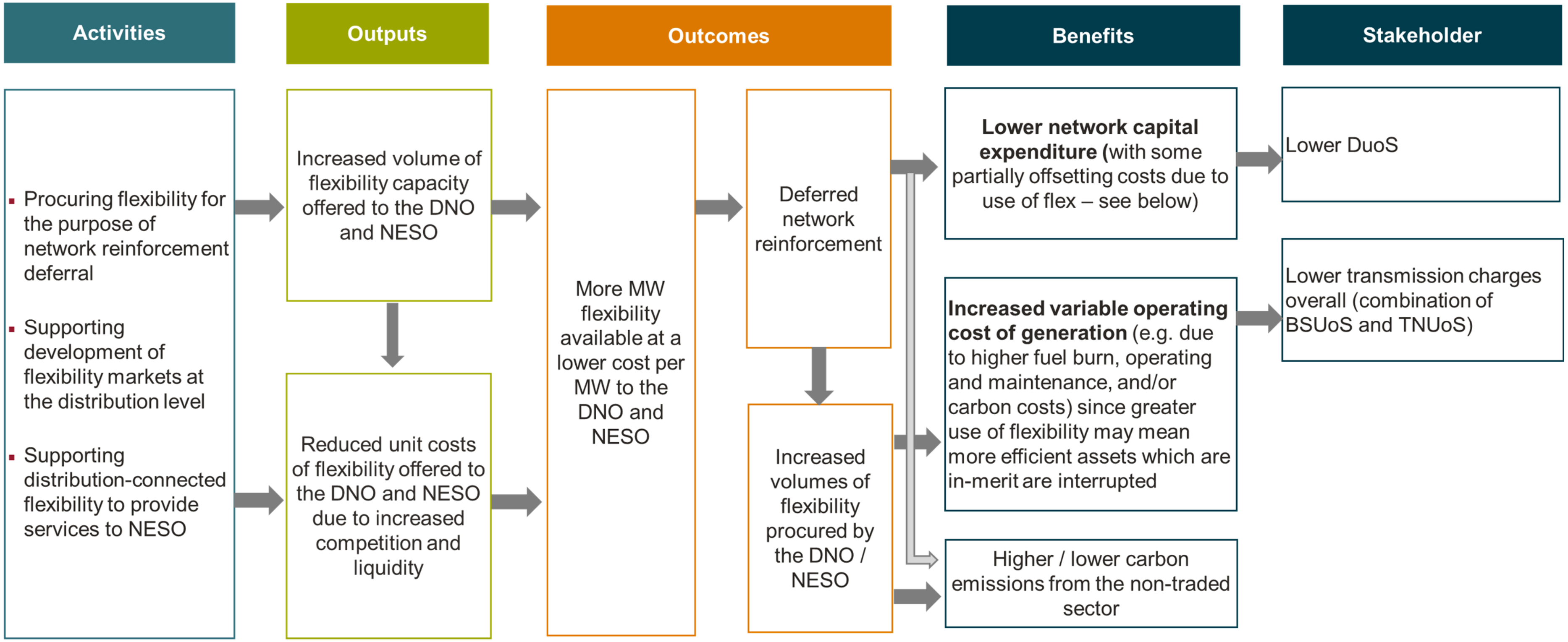
- **Flexibility providers** and the **distributed energy resources** they contract with will obtain revenue from greater use of flexibility services. In the medium to long term, this higher revenue potential is expected to attract more providers into the market and increase competition. Greater competition should in turn reduce the cost of flexibility for consumers. Over time, a well-functioning and competitive flexibility market should prevent excessive profits while still providing enough incentive through revenue or other benefits to keep providers engaged.

- **DNOs** and **NESO** will benefit from access to lower cost ways of balancing the system. However, over the long-run, we would expect price controls to mean that these benefits would flow through to consumers through lower DUoS, BSUoS and TNUoS charges.

The ultimate beneficiaries would be domestic and I&C **customers** who will benefit from the reduced network expenditure through lower bills.

26 Given the need to balance supply and demand across the national system, this additional local generation will result in a generator elsewhere reducing output, creating some offsetting cost savings that we do not model. However, the local generator providing flexibility is typically assumed to have higher variable costs (since it would otherwise have been in-merit and generating, and thus unable to provide flexibility). Therefore, the net effect is still a cost

Figure 9 Theory of change: Activities that help customers to participate in a flexible energy system



Source: Frontier Economics

4.3 Activity 1: Procuring flexibility for reinforcement deferral

This section sets out the quantitative KPIs that demonstrate the scale of this activity. We then describe the approach we have taken to benefits quantification, and the resulting social NPV figures.

4.3.1 Quantitative KPIs

As explained above, the benefits estimation focuses on sites where SPEN has contracted flexibility for the first time, regardless of when flexibility was originally identified as a cost-effective alternative to reinforcement or when reinforcement would have occurred in the counterfactual scenario.

However, this approach captures only the final stage of a broader decision-making process. SPEN's actual commitment to using flexibility is what effectively unlocks the expected stream of benefits. This final step is preceded by a structured, multi-stage activity made up of the following steps:

- **Step 1:** SPEN regularly carries out network assessments to identify locations that are currently, or are expected to become, capacity constrained in the short to medium term. The assessment determines how much additional capacity is needed to address these constraints, taking into account projected growth in demand, new generation connections, and external policy factors such as decarbonisation.

- **Step 2:** SPEN then conducts an engineering assessment of all possible solutions to address the constraints. This includes reinforcement, flexibility, network reconfigurations, and other innovative options.

- **Step 3:** For sites where flexibility is technically viable, SPEN runs tenders to gather market information on the availability and cost of the required services. SPEN's maximum willingness to pay is based on the cost of the next-best non-flexibility solution, usually the annualised cost of reinforcement.

- **Step 4:** Once the tendering process is complete, SPEN uses the results to carry out a detailed cost-benefit analysis of all available options, including flexibility.

- **Step 5:** The cost-benefit analysis identifies the solution with the highest benefit to cost ratio. This informs SPEN's decision on the preferred approach.

- **Step 6**: If flexibility is the most cost-effective option, SPEN begins tendering flexibility at the site in the years when it is needed.
  - SPEN may only be successful in contracting flexibility for a subset of the sites or time periods for which tenders were issued.

  - Flexibility is not only tendered at locations where it is needed immediately to defer reinforcement. SPEN also runs auctions for both current and future flexibility requirements. This includes newly identified sites as well as sites where the need for flexibility was established in a previous year. Again, we can distinguish between the MW of flexibility which was tendered, and the resulting amount that was contracted.

- **Step 7:** Dispatching flexibility which was procured in earlier years for delivery this year.

Some of the steps outlined above generate additional metrics or KPIs that SPEN tracks over time. These indicators help quantify the volume of SPEN's activities across different stages of delivering flexibility to defer reinforcement. Table 6 below presents selected KPIs relevant to these stages. All of the metrics shown relate specifically to scheduled utilisation flexibility. Flexibility services more suited to operational purposes are described separately in Section 8).

Table 6 KPIs: Flexibility to defer reinforcement

		Delivery year	
KPI	**Unit**	**2023/24**	**2024/25**
Number of **new** sites for which SPEN has identified flexibility could provide value and **tendered** for flexibility for the first time	#	17	5
Number of new sites for which SPEN has successfully **contracted** flexibility	#	8	11
Total peak flexibility **tendered** in any year across **all** sites, for specified delivery year	MW	240	444
- of which tendered prior to delivery year	MW	N/A	146
Total peak flexibility **contracted** in any year across **all** sites, for specified delivery year	MW	22	73
- of which contracted prior to delivery year	MW	N/A	49
Flexibility being delivered within the year	MW	250	320
Gross cost of deferred capex within the given year across all sites	£m	21.24	34.74

Source: SPEN

4.3.2 Benefits quantification

Methodology

We estimate the benefits of this activity in the following steps.

1. We define the activity and the counterfactual;
2. estimate the net value of deferral using the CEM methodology;
3. translate the benefit into a consumer bill impact; and
4. estimate the social benefits of changes in non-traded carbon emissions.

Step 1: Defining the activity and the counterfactual

As noted in the previous section, procuring flexibility is a 'multi-step' activity, including:

- the identification of a potential need to reinforce;
- an assessment of whether flexibility is the appropriate solution;
- tendering for flexibility; and
- contracting flexibility (noting that flexibility can be contracted in one year, for delivery over multiple future years);[27] and dispatching flexibility.

In line with the principles set out in section 3 we measure the benefits of flexibility at one stage in this 'multi-step' process and focus on the 'new activity' carried out in the regulatory year. This avoids double-counting (e.g. considering the benefits of flexibility both when it is contracted, and when it is delivered). We therefore define the activity and the counterfactual in the following way:

- **Counterfactual:** The DNO would continue to use the flexibility it has already contracted for specific sites, and would continue to contract flexibility for these sites as set out in its previous EJPs. This avoids a counterfactual where the DNO suddenly stops procuring flexibility, which could result in it being unable to reinforce in sufficient time. However, under the counterfactual, the DNO would not contract flexibility for new sites.

- **Activity**: We define the DNO's new activity in 2024/25 as the *contracting* of flexibility for *new* sites (i.e. sites for which the DNO has not contracted flexibility in the past, but which are expected to need reinforcement in future). We then attribute all current and future benefits of this contracting to the year in which the contract was put in place. Specifically, we calculate the benefits associated with:

[27] Contracting involves the formal agreement between the DSO and a flexibility provider, outlining the terms of service. Conversely, tendering refers to the process where the DSO issues an open invitation for flexibility providers to submit bids subject to DSO's requirements. Finally, procurement is the broader term encompassing both tendering and contracting.

  - Flexibility contracted for new sites in the *current regulatory year*; and

  - Flexibility that will be contracted in *future years* for these same sites (where the future requirement is known based on the SPEN's EJPs). We include this future contracted flexibility because most 'scheduled utilisation' flexibility is being contracted ahead of need, to ensure that it can be relied upon in future when it is required. There is a clear benefit to this activity as it unlocks the use of flexibility in the future. If these future benefits were not included then the activity would (incorrectly) appear to have a net cost to consumers.

- We exclude:

  - Any areas where flexibility is being tendered this year, but was also contracted in the past. This avoids double-counting, as the benefits associated with these activities would have been allocated to a previous year (should this quantification methodology have been in use).

  - Auctions that yield no contracts are excluded (they are assumed not to have happened).

To illustrate this, Figure 10 shows an example of a number of different sites, and in which years flexibility is planned to be contracted, and used. For the purpose of our assessment:

- Site 1 would **not** be included. This is because flexibility was successfully contracted in the 2023/24 regulatory year. The expected costs and benefits of flexibility in this site would therefore be allocated to 2023/24, rather than 2024/25.

- Site 2 would **not** be included. Although flexibility was contracted in both 2023/24 and 2024/25, the tendering this year was envisaged as part of SPEN's previous EJP. The expected cost and benefits of flexibility in this site would therefore still be allocated to the activity last year, rather than this year.

- Site 3 **would** be included, as flexibility is being contracted for the first time during this year. The expected stream of costs and benefits over the lifetime of the flexibility scheme would be estimated, similar to in the CEM.

- Site 4 **would** also be included. Again, 2024/25 is the first year for which flexibility is being contracted for this area. We would also include the expected costs and benefits relating to the additional contracting that SPEN envisages will take place in 2029.

- Site 5 would **not** be included. This is since SPEN does not envisage contracting flexibility until 2026. We only count a site once flexibility has been successfully contracted. This avoids counting benefits of sites where it subsequently turns out that it is not possible to procure cost-effective flexibility.

Figure 10 Illustrative example of when we count the costs and benefits of flexibility for reinforcement deferral

Example	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	Benefits assessed in 2024/25?
Site 1		Contract	Use	Use	Use				No
Site 2		Contract	Contract	Use	Use	Use			No
Site 3			Contract	Use	Use	Use			Yes
Site 4			Contract	Use	Use	Use	Contract	Use	Yes
Site 5				Contract	Use	Use	Contract	Use	No

Source: Frontier Economics

Step 2: Estimate the net value of deferral using the CEM methodology

We use the Common Evaluation Methodology (CEM) calculations to calculate the present value of a deferral in reinforcement costs (based on reinforcement cost estimates by SPEN):

- Outturn costs for auctions which have already been carried out are taken from SPEN data. Forecast costs for auctions which have not yet carried out are taken from SPEN forecasts.
- Figures from SPEN's CEM modelling, combined with site-specific Engineering Justification Papers (EJPs), are used to determine the number of years for which reinforcement is deferred.
- The expected costs of using flexibility are subtracted to produce a net benefit figure.

Step 3: Bill impacts

We focus on estimating the bill impacts for domestic customers. Our methodology relies on the following assumptions:

- In the long run, any savings arising from deferred capital expenditure, relative to the reinforcement counterfactual, will flow through into in the allowed revenues of the DNO and be reflected in DUoS charges.
- Any percentage reductions in allowed revenue will result in a corresponding percentage reduction in the average domestic DUoS charge.

Under these assumptions we take the following steps:

- We obtain the average domestic DUoS charge from Ofgem's RIIO-ED2 publication, which indicates that charges are expected to remain around £100 per year in 2020/21 prices, over the ED2 period (equivalent to approximately £131 in 2024/25 prices).[28]
- We calculate the NPV of the estimated savings generated by this activity, as a proportion of SPEN's allowed revenues in 2024/25. Specifically, we find that the NPV of the estimated savings corresponds to a 0.64% reduction in SPEN's allowed revenues for this regulatory year.[29]
- Applying this 0.64% saving to the average DuoS charges translates into a long-run saving of approximately £0.84 for the average domestic customer.[30]

The bill savings we present are the net present value of savings which would likely flow through many years' worth of bills. They should therefore be interpreted as an equivalent one-off saving for customers from this year's activities, rather than a saving that would be made year after year.

Step 4: Social costs of non-traded emissions

Some of the dispatched flexibility comes from generators that emit CO_2 but are not covered by the UK ETS.[31] This means that certain flexibility solutions may cause CO_2 emissions that have not been accounted for by the ETS, resulting in an incremental societal cost.

To estimate the cost of these non-traded emissions, we follow these steps:

1. **Determine the relevant share of contracted capacity:** We analyse procurement data from 2021 onwards to determine the share of contracted flexibility provided by fossil fuel or gas generation, where required flexible capacity is below 20MW[32]. We take a conservative approach by assuming that this share is not covered by the ETS. We estimate that c. 14% of the contracted capacity satisfies these criteria.
2. **Determine average flexibility utilisation:** Using SPEN auction and dispatch data for the current regulatory year, we calculate the average annual utilisation of

28 Ofgem ED2 Ofgem confirms local electricity networks price control for 2023 to 2028 | Ofgem

29 The NPV of the savings is £3.9 and the allowed revenues of SPEN in 2024/25 is £603m, which gives a percentage of 0.64%.

30 The saving of 0.64% multiplied by the typical annual bill of £131 translates into a saving of £0.84 over the long term.

31 The UK ETS applies to regulated activities that result in greenhouse gas emissions, including on-site combustion from units with a total rated thermal input exceeding 20MW

32 Some fossil fuel–based flexibility providers may already fall under the scope of the ETS, as their total installed generation capacity may exceed the 20 MW threshold—even if only a portion of that capacity is utilised for providing flexibility services.

the contracted flexibility capacity (%) and apply this to the MW of capacity estimated in the previous step. [33]

3. **Assume generation technology:** We assume that this generation is provided by small to medium diesel generators with an average efficiency of 30% (noting that DESNZ estimates suggest a range of 25% to 35%).
4. **Calculate societal cost:** We apply DESNZ carbon conversion figures and traded carbon costs to compute the societal cost per MWh of electricity generated by these diesel generators.[34] [35]
5. **Allocate cost to contracted capacity**: Finally we apply this societal cost per MWh to the capacity of flexibility estimated in step 2.
6. **Estimate total annual cost:** We sum the net present value (NPV) of costs across all sites where flexibility has been contracted for the first time within the regulatory year. This provides an estimate of the total incremental cost associated with additional actions taken in that year.

Key uncertainties and limitations

There are some uncertainties regarding this methodology:

- **Option value of flexibility is not included:** The estimation of the impacts is based on SPEN's forecasted flexibility utilisation and cost. This will lead to uncertainty in the long-run NPV of flexibility. These uncertainties mean that flexibility has an additional option value: Given these of uncertainties, flexibility can 'buy time' to defer a decision on reinforcement until more information is known.

- **Non-delivery risk not included:** If a DNO chooses to use flexibility, but a combination of non-delivery of flexibility or greater demand growth means that asset headroom is exceeded, then there may be very high costs (e.g. the need to reduce uptake of LCTs, or even asset overloading and failure). As the modelling does not account for uncertainties, these risks are not accounted for.

- **Reinforcement costs are assumed to stay constant in real terms:** In recent years, reinforcement costs have often increased faster than general inflation. This effect reduces the value of deferral but is not reflected in our methodology, as it is also not included in Ofgem's Common Evaluation Methodology (CEM), which we follow to remain consistent with industry practice.

- **All figures relate to expectations.** If key inputs such as the cost of flexibility or rate of demand growth turn out systematically differently to expectations, then the outturn

---

33 Procured flexible capacity is measured net of losses. While actual emissions may be slightly higher due to transmission and distribution losses, these are considered negligible here given the local nature of flexible generation relative to demand.

34 DESNZ 2024: [Greenhouse gas reporting: conversion factors 2024 - GOV.UK]

35 DESNZ 2024: [Traded carbon values used for modelling purposes, 2024 - GOV.UK]

benefits of these activities will be higher or lower than estimated here. However, these types of uncertainty will exist for any ex-ante CBA, and over time we would expect that SPEN's experience running flexibility auctions will enable it to validate and refine these assumptions.

- **Non-traded carbon cost based on technology assumptions:** When calculating the cost of non-traded carbon, we make high-level assumptions that all fossil fuel-based flexibility is provided by small- to medium-scale diesel generation. We also apply corresponding assumptions regarding efficiency. In addition, assumptions on the share of overall flexibility provided by fossil technologies and their annual utilisation are informed by historical flexibility procurement and dispatch data.

Results

The results are presented in Table 3 below. From the top of this table:

- The first row shows the time value of the expected deferred reinforcement associated with flexibility schemes for which procurement first successfully took place this year.
  - In line with the approach we have used elsewhere in this report, we have separately reported those benefits expected to accrue during the current year, and current price control period. These are shown in the first two columns. However these figures should be treated with caution: A flexibility scheme which defers spend on reinforcement from 2024/25 to 2025/26 will appear to have an extremely high in-year benefit, as the entire benefit of reinforcement has been avoided in that year. However, when looking at the longer term, this is just a deferral. **We therefore suggest focussing on the long-run figures.**
- The second row shows the associated expected costs of flexibility.
- The third row nets off these two figures to produce a societal net benefit which would, in the long-term, be expected to be reflected in customer bills.
- The fourth row calculates the resulting long-term change in customer bills.
- The fifth row quantifies the costs of flexibility associated with increased non-traded carbon emissions. As described above, these costs are not currently internalised: They reflect a cost to society but are not reflected in customer bills.

Overall we estimate that SPEN's 2024/25 flexibility procurement, for sites already in the ED2 plan where flexibility is contracted for the first time, leads to a long-term net benefit to society of £3.9m.

Table 7 Benefits quantification: Flexibility to defer reinforcement

Cumulative benefit	In-year Apr 24 – Mar 25	Rest of ED2 Apr 24 – Mar 28	Long-term Apr 24 – Mar 83
Benefits from deferred reinforcement	£3.0m	£3.2m	£8.0m
Costs of flexibility	(£0.00m)	(£0.03m)	(£4.1m)
Net benefits to society reflected in customer bills	**£3.0m**	**£3.2m**	**£3.9m**
NPV of bill savings over the long-term (£ per customer)			£0.84
Costs of non-traded emissions	(£0.001m)	(£0.007m)	(£0.007m)
Total net benefits to society	**£3.0m**	**£3.2m**	**£3.9m**

Source: Frontier analysis of SPEN data

Note: Figures shown in 2024/25 prices, and are based on proportionally scaled outturn data from April 2024 to January 2025, to account for the unavailability of February and March 2025 data at the time of analysis.

4.4 Activity 2: Developing the market for flexibility at the distribution level

This section sets out the quantitative KPIs that demonstrate the scale of this activity. We then describe the approach we have taken to benefits quantification, and the resulting social NPV figures.

4.4.1 Quantitative KPIs

As explained above, SPEN's market development activities are intended to lead to increased competition and liquidity in the market for flexibility. An intermediate outcome of this will be an increase in the number of providers participating in flexibility markets, which is summarised below in Table 8, together with some high-level metrics on the development activities themselves.

Table 8 shows that SPEN has significantly scaled up its market-facilitating activities in the 2024/25 regulatory year. This is reflected in both activity-level and output-level KPIs. For example, SPEN has tripled the number of stakeholder engagements, including events and bilateral meetings with key stakeholders. These efforts have contributed to a 29% increase in participating providers and a 211% increase in assets registered on Piclo.

One significant change SPEN has introduced in this regulatory year is the shift from longer-term contracts to shorter-term, month-ahead markets. This change has led to two key benefits for both SPEN and its consumers:

- **Improved reliability of flexibility procurement:** The share of tendered flexibility that is successfully contracted has increased from 44% to 100%. We understand from SPEN that this improvement is largely due to providers having greater certainty over asset availability in month-ahead markets. In contrast, under longer-term contracts, providers often overestimated the number of assets that would be operational at the time of delivery, leading to a lower conversion rate from procured to contracted flexibility. Improved reliability builds confidence in flexibility as a dependable solution and encourages greater use of flexibility by SPEN, supporting more efficient market operation over time.

- **Better alignment between contracted and dispatched flexibility:** In 2024/25, all contracted flexibility was successfully dispatched, which SPEN indicates reflects improved planning accuracy. SPEN now has greater visibility of its flexibility needs in the month-ahead window, reducing the need for higher availability payments that were previously required to hedge against uncertainty in long-term procurement.

Table 8 KPIs: Developing the market for flexibility

KPI	Unit	2023/24	2024/25
Activity-level KPI			
Stakeholder events	#	7	11
Bilateral surgeries	#	35	109
Output-level KPI			
Flexibility providers participating in auctions in the regulatory year	#	7	9
Assets registered on Piclo	#	3,577	33,394
Flexibility locations available for tendering	#	N/A	40
Domestic flexibility available through platform provider	MW	N/A	325
Reliability of the flexibility tenders, measured as a share of tendered flexibility that is contracted	%	44	100
Share of contracted flexibility that is dispatched	%	44	100

Source: SPEN data

4.4.2 Benefits quantification

Methodology

We estimate the benefits of this activity in four steps.

Step 1: Defining the activity and the counterfactual

The counterfactual and activity are defined as follows:

- **Counterfactual:** The DNO would not have carried out any further activities during 2024/25 aimed at developing the market for flexibility.
- **Activity**: The activities described in section 4.1.2 are carried out.

Step 2: Illustrating the impact of these actions

Compared to the counterfactual, these activities should result in more flexibility providers coming forward, with more flexibility available at a lower cost to the DNO (in economic terms, a shift outwards in the supply curve for flexibility). Fully calculating this impact would require looking at the supply and demand of flexibility on an area-by-area basis: For example, there might be some sites where, without the extra flexibility which comes forward, it is impossible to rely on flexibility to defer reinforcement. However this is both impractical (given the significant uncertainties) and also unnecessary (since, as described below, the activities relating to the *procurement* of flexibility quantified within our framework will ultimately pick up the impacts of these market development activities.

As a simplification, we have therefore assumed that the only impact of these activities is to reduce the cost of flexibility compared to what it would otherwise have been.

An assumption needs to be made on what this impact will be. Insufficient data is available to estimate this quantitatively (e.g. econometrically), as market development activities have only been carried out for a relatively short period of time, and their impact on flexibility prices will likely be dwarfed by other factors such as fuel prices, or the variation of flexibility availability between different areas. **We have therefore made an illustrative assumption that activities carried out this year will reduce the cost of all future flexibility by 1%**. This assumption is intended as a starting point, and can be updated as further evidence becomes available on the effectiveness of actions to develop flexibility markets.

Step 3: Multiply by estimates of future flexibility costs

These activities are assumed to reduce the cost of flexibility procured this year and in future years. We have estimated the cost of this flexibility as follows:

- For RIIO-ED2, we have used the projected flexibility costs from SPEN's Engineering Justification Papers (EJPs) for all sites where flexibility is being procured, regardless of its intended use (i.e. we capture all use cases of flexibility, not only flexibility for deferral of reinforcement).
- For RIIO-ED3 and beyond we adopt a similar approach for sites with existing EJPs. Additionally, we assume that an incremental 200MW of peak flexibility capacity will be procured annually. This is based on the high-level expectation (provided to us by SPEN) that approximately 1GW of currently uncontracted flexibility will be required during ED3 to meet SPEN's targets. We assume the average cost of this additional flexibility is equal to the average annual flexibility cost across all sites, as forecast in the EJPs for RIIO ED2 and ED3.

Step 4: Bill impact

We apply the same methodology as used when calculating the bill impact from deferred reinforcement.

Key uncertainties and limitations

As described above, the figure that we have estimated is subject to considerable uncertainties and so should be seen as illustrative in nature. However, by providing a plausible order-of-magnitude estimate of the potential benefits of these activities, it can help show that they have the potential to bring substantial societal benefits.

However, the value of these activities should not be added to the combined total for all other activities for the following reasons:

- Given the large number of highly heterogenous market development activities carried out, it has not been possible to estimate a cost associated with them. We are therefore only able to present a *gross* benefit, unlike the other benefits we calculate which are in *net* terms.

- The actual costs of flexibility that we use to quantify flexibility procurement for operational purposes will already account for the impact of past market development activities. Similarly, the expected costs of flexibility used to calculate the benefits of flexibility for deferral will implicitly build in expected market developments. This will be the case for any future submissions based on this framework too, meaning that if the benefits described below were incorporated in a total NPV, over time there would be double-counting as these benefits would also be captured in the procurement of flexibility itself.

Results

The results are presented in Table 9. The table shows that the cost-reduction benefits of SPEN's market facilitation actions, as estimated by our methodology, increase with the length of the time horizon considered.

We expect the cost-reduction benefit in the current year to represent only 1% of the total forecast flexibility spend for the year, which is approximately £1,300. However, because we assume that actions taken today reduce not only current but also future flexibility costs (adjusted for the discount rate), the cumulative benefits grow significantly over time. They rise to around £50,000 over RIIO-ED2 and reach approximately £2.4 million in the long term (or £0.53 saving per customer).

This suggests that most of the cost-reduction benefits from SPEN's market facilitation activities undertaken this year are expected to materialise after ED2.

Table 9 Benefits quantification: Developing the market for flexibility

Cumulative benefit	In-year Apr 24 – Mar 25	Rest of ED2 Apr 24 – Mar 28	Long-term Apr 24 – Dec 67
Gross benefits to society reflected in customer bills	£0.0013m	£0.05m	£2.43m
Gross PV of bill savings over the long-term (£ per customer)			£0.53

Source: Frontier analysis of SPEN data
Note: Figures shown in 2024/25 prices

5 Enabling capacity for customer connections, growth, and decarbonisation (part 1)

In this section we describe the benefits associated with SPEN's activities in regulatory year 2024/25 to enable capacity for customer connections, growth, and decarbonisation.

Given the large number of activities in this group, we discuss these activities, and the associated benefits, into two parts:

- First, we discuss the activities relating to connecting generation and storage as well as large demand users ('Part 1').
- Second, we discuss the activities relating to network planning activities ('Part 2').

The remainder of this section focuses on Part 1. The specific activities considered as part of this activity group are summarised in the table below. Part 2 is covered in section 5 of this report.

#	Activity	Qualitative link to benefits	Quantitative KPI	Quantified benefit
Enabling capacity for customer connections, growth, and decarbonisation				
Part 1				
4	Offering flexible generation / demand connections through LMS and Technical Limits to manage *transmission* constraints[36]	✓	✓	✓
5	Offering flexible connections under reformed network access storage rights for storage	✓	✓	✓
6	Offering flexible generation / demand connections under other schemes to manage *distribution* constraints	✓	✓	✓
7	Developing a connections analytical tool to improve accuracy of curtailment forecasts	✓	×	×

This section is structured as follows:

- In section 5.1, we describe SPEN's activities in 2024/25.
- In section 5.2, we set out the theory of change linking these activities to societal and consumer benefits.

[36] Technical limits in SPM applies to generation; LMS in SPD applies to demand and generation.

- In section 5.3, we then set out our methodology and results for quantifying the benefits of SPEN's 2024/25 activities relating to offering flexible connections (i.e. activities 4, 5 and 6 from the table above).

5.1 SPEN's activities in 2024/25

5.1.1 Activity 4: Offering flexible generation / demand connections through LMS and Technical Limits to manage transmission constraints

In 2024/25, SPEN has:

- Used **Load Management Schemes ('LMS'**) in the SPD network to connect customers to the distribution network earlier and ahead of transmission reinforcement works. [37]

- Established **Technical Limits** at the boundary with the transmission network. SPEN has collaborated with NGET and NESO to establish operational limits at the transmission and distribution boundary in the SPM network to allow the DNO to manage the power flows at the GSPs and connect distribution customers on a flexible basis ahead of transmission reinforcement works at these GSPs.

These activities correspond to Ofgem's baseline expectation 2.2.2 which states that:

'DNOs to have and regularly review a decision-making framework for when DER are instructed to dispatch in real-time…. This should promote co-ordination across services (including curtailment as part of non-firm connection agreements and ESO flexibility services)… and ensure dispatch results in the best outcome for the whole system; this includes service provision to the ESO and other distribution networks'

They also correspond to activity 1.1.4: '*DNOs to have in place transparent and robust processes for identifying and assessing options to resolve network needs, using competition where efficient*'.

The monitoring carried out as part of LMS is also related to Ofgem's baseline expectations including 2.1.1 ('*DNOs to improve network visibility and identification and sharing of operability constraints…'*)

---

[37] SPEN defines Load Management Schemes ('LMS') as "*a system comprised of geographically distributed measuring devices and site-specific customer interfaces to detect, in real-time, unacceptable overloading of transmission assets to disconnect the generation contributing to the overload in accordance with contractual arrangements*." See SPEN website, Accelerating distribution connections.

5.1.2 Activity 5: Offering flexible connections under reformed network access storage rights for storage

Given the growth in volumes of electricity storage connecting to the network, the ENA's Strategic Connections Group ('SCG') reviewed potential solutions to the challenge of constrained network capacity. The SCG set up three workgroups, and one of these, the Battery Storage Connections ('BSC') workgroup was asked to review the connection arrangements for distribution electricity storage customers.

In 2024/25, SPEN has been involved in the following areas of work:

- **Implementing reformed storage network access rights for *new* storage connections (referred to by SPEN as 'Phase 1'):** This work defined standard network access rights for all new distribution-connected storage assets, specifying the conditions under which distribution-connected storage can be curtailed by the DNO.[38] In 2024/25, SPEN has used these standards when contracting with new storage connections.
- **Assessment of the case for applying reformed network access rights to *existing* storage connections retrospectively (referred to by SPEN as 'Phase 2').** We understand that SPEN played a leading role in the industry work to understand whether the reformed storage network access rights (as per 'Phase 1') should be applied to retrospectively to existing connected and contracted distribution storage. We understand that a socioeconomic assessment was carried out which confirmed that the implementation of reformed network access rights would lead to substantial benefits, but that there were fewer benefits associated with retrospective application. As a result no further actions were taken on this activity.[39]
- **Implementing reformed storage network access rights for new storage connections at the T/D interface (referred to by SPEN as 'Phase 2a'):** SPEN has led and implemented industry work on defining the planning assumptions used at the T/D interface resulting in reduced reinforcement requirements at the GSP substation to accommodate storage import capacity.

These activities also relate (among other items) to paragraphs 2.2.1 and 1.1.4 of Ofgem's baseline expectations, quoted above.

38 Simply put, the DNO does not need to reinforce to secure the import request of the BESS under N-1 on the distribution network, whereas before the DNO did. For more detail, see ENA (September 2023), Battery Storage Connections – Tactical Solutions Guidance Notes, see Tactical Solutions 1 and 2.

39 Oxera (November 2024), Standardising access rights for electricity storage – Socioeconomic impact assessment.

5.1.3 Activity 6: Offering flexible generation / demand connections under other schemes to manage distribution constraints

In 2024/25, SPEN has offered flexible connections to manage distribution network constraints through a combination of:

- **Active Network Management (ANM):** A wide-area system used to dynamically manage power flows and maintain system stability, adjusting generation and load in real-time to keep the network within safe operating limits, avoiding distribution network reinforcements.
- **Local Management Zones (LMZ):** Used to manage *local* network constraints by curtailing generation or load following network outages, avoiding distribution network reinforcement.
- **Remote monitoring:** used to manage *remote* network constraints, by curtailing generation or load following remote network outages, avoiding distribution network reinforcements.

5.1.4 Activity 7: Development of 'Constraint Identification and Curtailment Analysis' tool

In 2024/25, SPEN has developed a 'Constraint Identified and Curtailment Analysis Tool', in collaboration with Smarter Grid Solutions ('SGS'). This tool carries out more advanced assessment of future curtailment, allowing SPEN to provide more accurate indications of expected curtailment levels to customers.

Relevant aspects of Ofgem's baseline expectations include 3.1.2: '*DNOs should, with stakeholder input, develop robust strategies for how they will collate and publish more helpful information, wherever possible consistently and in coordination with other network licence holders, and communicate this clearly.*' Expectation 1.1.3 regarding the sharing of network planning information (e.g. to help users understand where to connect) is also relevant.

5.2 How these activities link to benefits

The logic model in Figure 11 below illustrates how these activities ultimately flow through to benefits for wider society and specific stakeholders.

5.2.1 Outputs

Offering flexible connections through Technical Limits / LMS means that new customers are less likely to trigger new constraints, or exacerbate existing constraints, so they can be connected without the need for reinforcement, reducing the cost and time to connect these customers. Similarly, standardising network access rights (e.g. requiring less 'headroom' to be allocated to storage connections) means that new storage sites need less network infrastructure to be accommodate them, also reducing the cost and time involved with connecting these assets.

These activities should therefore lead to:

- more connections being offered within a given timeframe; and
- reduced connection times on average.

Shorter connection queue times, combined with greater certainty around expected curtailment (from the enhanced forecasting tool) and lower connection costs, should lead to **lower costs of capital for new investment** as investors factor these into their project appraisals. Standardised network access rights may also make it easier for storage customers to develop projects since there is only one common set of rules across all DNOs to be understood, reducing uncertainty and project risk.

5.2.2 Outcomes

Given the shorter waiting times, the DNO should be able to efficiently connect generation, storage, and demand more quickly. This leads to:

- **More efficient generators displacing generators with higher costs (and potentially carbon emissions):** The earlier connection of generation assets with lower variable costs (for example, renewable generators) should displace less efficient (e.g. fossil fuel) generation assets in wholesale power markets. The accelerated connection of storage assets may further support the displacement of less efficient generation technologies by absorbing surplus renewable generation and discharging during periods of low renewable generation (i.e., when fossil fuel generation is likely to be in merit).
    - There is potentially a countervailing effect if the use of a flexible connection leads to generators' output being curtailed.
- **Earlier production and consumption of goods and services:** The earlier connection of demand-side customers (e.g. a data centre) means that goods and services can be produced and consumed earlier than they would otherwise have been.
    - There are potentially two countervailing effects. First, the use of a flexible connection may lead to demand being curtailed (or the requirement for back-up generation).[40] Second, the additional consumption from advancing demand-side

[40] There is a natural limit to this effect as, if it was too severe, investors would choose a firm connection over one that can be curtailed.

customers will require an increase in generation volumes, with associated increases in system operating costs.

- **Avoided network reinforcement investment:** Customers which would previously have been connected using a firm connection are now connected with a flexible connection and subject to curtailment. The ability to curtail these connections during periods of network constraint may enable the DNO to manage congestion without having to reinforce, therefore delaying or reducing the costs of network reinforcement.[41] This applies to generation, storage and demand connections.

5.2.3 Societal benefits

The resulting societal benefits are:

- **Earlier reductions in variable operating costs of generation** from less expensive (e.g. renewable) generation displacing more expensive (typically fossil fuel) generation sooner.[42] [43] Storage assets may further reduce system operating costs by charging during periods of surplus renewable generation (e.g. "consuming" surplus wind generation which would otherwise be curtailed). Storage may then dispatch during periods of low renewable generation, displacing some generation from more expensive (fossil fuel) generation. Note that the impact of curtailment in reducing generation and storage output would need to be netted off against these benefits.

- **Lower network capital expenditure** arising from the avoidance of network reinforcement for generation, storage and demand connections.

- **Earlier realisation of the economic / private benefits** from the consumption and production of connected business and domestic consumers (again, with any disbenefits of curtailment and increased electricity system operating costs linked to the higher demand netted off); and

- **Earlier realisation of reduced investment costs** from lower cost of capital arising from reduced risk / uncertainty of investments.

5.2.4 Stakeholder benefits

Reductions in network capital expenditure associated with new connections (whether of generation or demand) will initially reduce costs for the networks (as well as the customer themselves to the extent that they pay for a proportion of connection costs). Ultimately all

41 To the extent to which investors would have paid for a portion of reinforcement costs themselves this will also reduce investors' costs, which could lead to additional investments being made.

42 We assume that any increases in wholesale costs resulting from running more generation to support the extra demand is more than offset by the benefits these demand-side assets bring to the wider economy.

43 Reduced system operating costs may also arise from newly connected assets participating in flexibility markets.

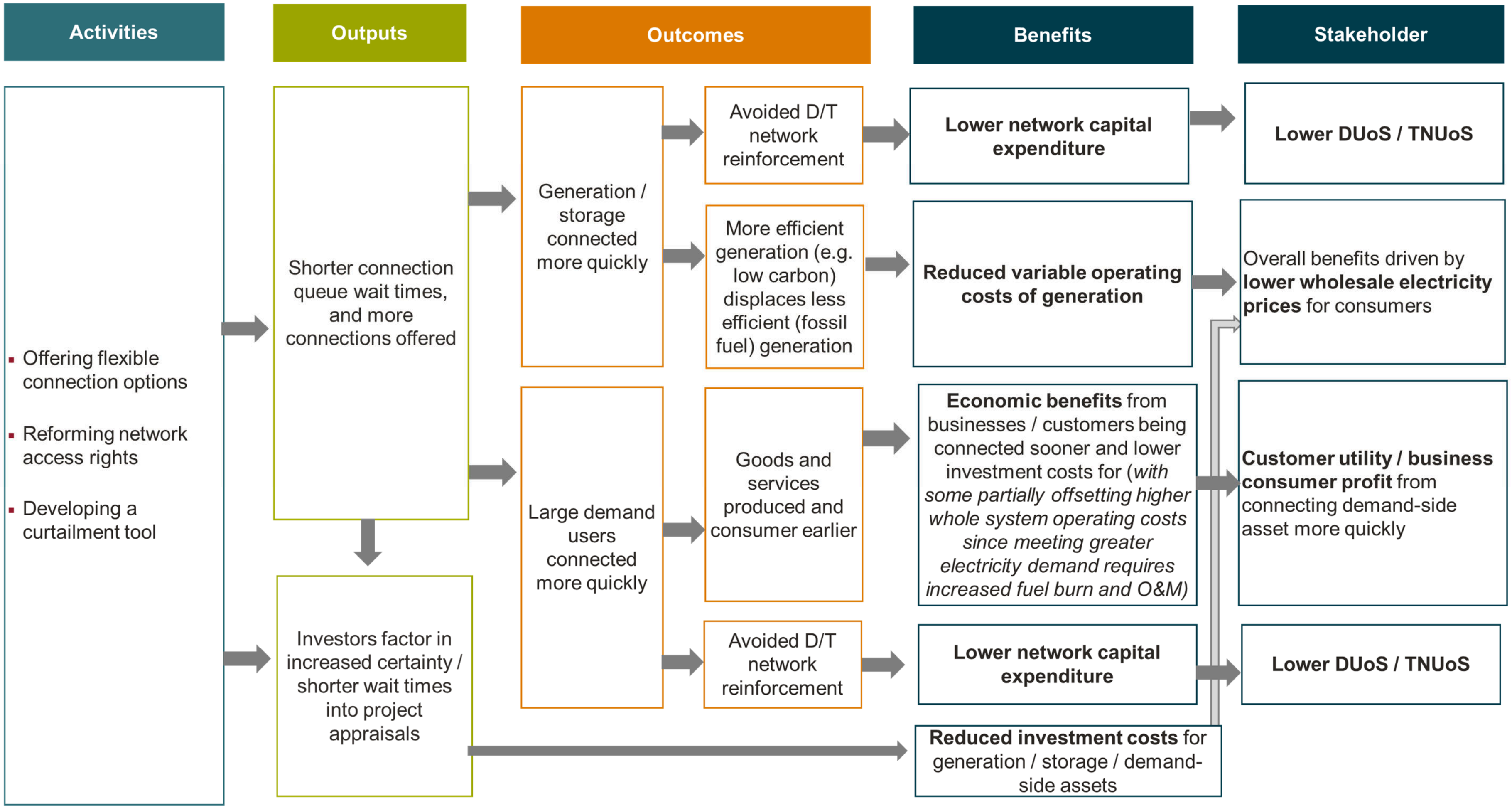
of these cost savings should accrue to customers (with the savings for networks flowing through to the bills of domestic and I&C **customers** through lower DUoS / TNUoS).[44]

Overall reductions in wholesale costs (and potentially including reductions in carbon emissions, priced through the UK ETS) due to generation and storage coming onto the system sooner or with lower costs will ultimately flow through into lower wholesale electricity costs within the bills of domestic and I&C **customers**.

The benefits of bringing demand forward will lead to benefits for **industrial and commercial customers** in the form of profits, in addition to welfare benefits from **domestic customers** (through greater access to the goods and services that they value). Unlike the other types of benefits above, these would not flow through electricity bills.

44 If newly connected assets participate in the flexibility market, there is further potential for lower DuOS / BSUoS, as these assets may increase competition in flexibility markets, reducing unit costs of flexibility.

Figure 11 Theory of change: Activities that facilitate flexible connections



Source: *Frontier Economics*

5.3 Offering flexible connections

This section sets out the quantitative KPIs that demonstrate the scale of SPEN's activities offering flexible connections. We then describe the approach we have taken to benefits quantification, and the resulting social NPV figures.

5.3.1 Quantitative KPIs

In 2024/25 SPEN has offered flexible connections under several different schemes (or in some cases, combinations of schemes), which it categorises as follows:

- **LMS/Technical Limits (activity 4):** Connections enabled through LMS / Technical limits, accelerating the connection of customers against transmission constraints (and working with the relevant transmission owner to do so).);
- **Storage Network Access Rights Reform (activity 5):** Connections enabled through reforms to network access rights for storage reforms, either through Phase 1 reforms (affecting new electricity storage sites connecting to the distribution network) or Phase 2a reforms (affecting new electricity storage sites connecting at the T/D interface).
- **Coordinated Solutions (activity 4 + activity 5):** Connections enabled through a combination of LMS / technical limits (1) and network access rights reforms at the T-D interface;
- **Flexible Connections (activity 6):** Customers enabled through another flexible connection, accelerating the connection against distribution constraints.

For more detail on each activity please see section 5.1 above.

Activity to bring forward flexible connections takes place across multiple stages. For example, in a given year, activities across SPEN will include:

- designing connection offers;
- providing connections offers ('quoting');
- contracting with customers (i.e. when customer accepts the connection offer);
- beginning the construction work to enable connection; and
- completing the work to enable the connection ('energisation' or point of 'connection').

We focus on two key points in this journey, namely the point of contracting with customers, and the point at which customers are connected (i.e. energisation). We report the number of customers contracted and connected under each scheme below.

Table 10 KPIs: Contracting customers in 2024/25

KPI	Unit	2024/25
Total number of contracted customers	**#**	**91**
Of which: via LMS/Technical Limits	#	27
Of which: via Reformed Network Access Rights	#	15
Of which: via Coordinated Solutions:	#	13
Of which: via other flexible connections	#	36
Total MW of contracted customers	**MW**	**2,339**
Of which: via LMS/Technical Limits	MW	1,045
Of which: via Reformed Network Access Rights	MW	226
Of which: via Coordinated Solutions:	MW	556
Of which: via other flexible connections	MW	512

Source: SPEN connections data

Table 11 KPIs: Connected customers in 2024/25

KPI	Unit	2024/25
Total number of connected customers	#	14
Total MW of connected customers	MW	366

Source: SPEN Connections data

5.3.2 Benefits quantification

Methodology

We estimate the benefits of this activity in the following steps:

1. We define the activity and the counterfactual.
2. We estimate the reduction in wholesale costs from connecting new generation and storage assets sooner (i.e., by avoiding the cost of running more expensive generation).
3. We estimate the avoided network reinforcement cost associated with issuing flexible connections.
4. We also provide an indication of the potential benefits supported in the wider economy of connecting demand-side assets sooner.

Step 1: Defining the activity and the counterfactual

As noted in the previous section, connecting customers to the electricity distribution network is a 'multi-step' activity. To avoid double-counting, we measure the benefits at one stage in this 'multi-step' process and focus on the 'new activity' carried out in the regulatory year. We define 2024/25 activity in terms of connections *contracted* this year, regardless of when the connections will ultimately be finalised. We do not account for connections *connected* during 2024/25 but contracted in an earlier year, as to be consistent the benefits of this activity should be allocated to those earlier years.

We therefore define the activity and the counterfactual in the following way:

- **Counterfactual**: In the counterfactual we assume that SPEN contracts customers on a firm basis, which typically requires reinforcement and a longer connection time frame (for this reinforcement to be carried out).
- **Activity**: SPEN contracts these customers on a flexible basis via DSO solutions, which means it is ultimately able to connect customers with flexible connections more quickly and with reduced reinforcement via the schemes set out above. [45]

In practice, it is unlikely that all connections *contracted* in 2024/25 will progress to physical *connection* to the grid. We therefore make an adjustment based upon SPEN's internal assessment about the likelihood of each contracted connection ultimately progressing to physical connection. This is based on various factors such as progression with NESO, and the potential impact of connections reform.

Step 2: Estimating the reduction in wholesale costs of connecting new generation and storage assets sooner

As explained earlier, the accelerated connection of less expensive (e.g. renewable) generation or storage may displace more expensive (typically fossil fuel) generation.

We estimate the wholesale costs benefits in four stages:

- For generation assets that have been contracted for accelerated connection we estimate the volume of generation (in MWh) that has been accelerated based on indicative load factors for different technology types published by DESNZ.[46]
  - When calculating the volume of generation which has been accelerated, we account for the exposure to **curtailment** for assets which have accepted a flexible connection offer in the actual scenario but which would have had firm network access in the

[45] In most instances, the asset is contracted with a flexible connection as a result of the activity. There are however, some instances where a *firm* connection date can also be accelerated as SPEN has identified additional headroom due to its implementation of reforms to network access rights for storage assets.

[46] DESNZ (November 2023) *Electricity Generation Costs 2023*

counterfactual (i.e., absent SPEN's initiatives to accelerate the connections). In practice, we do not have access to information on future levels of curtailment for each asset: this will depend on the future balance of demand, generation and network build at each location on the network. We therefore base estimates of future exposure to curtailment levels for these assets based on a notional curtailment assumption of 5% of annual consumption/generation provided by SPEN.

- We then calculate the saving in wholesale market costs (in £/MWh) arising from the earlier connection of this generation. Specifically, the saving is calculated as the difference between the:
  - **Counterfactual variable operating costs:** We estimate what the operating costs would have been in the counterfactual. We start with a simplifying assumption that the generation from these assets always displaces generation from a gas-fired generator (CCGT) in the wholesale electricity market and estimate the operating costs if this generation had been provided by a CCGT.[47] We use DESNZ forecasts on the running costs of a gas-fired generator, forecasts of carbon values, and fuel cost assumptions.[48]
  - **Factual variable operating costs:** We estimate the actual operating costs implied by the mix of generation asset that will be connected sooner. The generation technology mix has been provided by SPEN and technology-specific variable operating costs are again based on DESNZ forecasts.
- We then multiply the saving in wholesale market costs with the volume of generation accelerated to obtain the annual saving in wholesale market costs. These steps are shown through an illustrative example in Table 12 below.
- The final step is to calculate the net present value of the annual savings over the period for which these assets are assumed to be operational.

47 We note that further into the modelling period, an unabated CCGT may not be the marginal generator that is displaced by the newly connected assets. In practice, our calculations of the variable system operating cost saving assumes that the operating costs of a CCGT are a proxy for the operating costs of technologies that may be on the margin in future.

48 DESNZ (November 2023) *Electricity Generation Costs 2023 Annex B: Example levelized cost of electricity (LCOE) calculator*. Wholesale gas costs based on Ofgem Forward Delivery Contracts - Weekly Average (GB), averaged over 2024.

Table 12 Illustrative example – Annual opex saving

		Value	Unit
Counterfactual opex cost per MWh (CCGT)	[A]	100	£ / MWh
Factual opex cost per MWh	[B]	60	£ / MWh
Opex saving per MWh	[C] = [A] – [B]	40	£ / MWh
Volume of generation accelerated	[D]	100,000	MWh
Annual saving	**[E] = [D] × [C]**	**400,000**	**£ per year**

Source: Frontier Economics

For storage assets (batteries), we apply broadly the same methodology as for generation technologies described above. However, there are two differences to note.

- First, we make a simplifying assumption that the battery asset charges during periods of surplus onshore wind generation (i.e., wind generation which would otherwise have been curtailed) and therefore incurs factual variable operating costs (on a per MWh basis) which are equivalent to an onshore wind plant.
- Second, our estimates of the volume of CCGT generation which the battery will displace in wholesale electricity markets account, at a high-level, for technical constraints associated with a lithium ion battery operation, based on assumptions from DESNZ.[49]

Our wholesale market savings estimated above implicitly include the lower carbon costs from connecting renewable generation sooner since the cost of carbon allowances (purchased via the UK Emissions Trading Scheme) are reflected in the operating costs of the CCGT. However, in line with Ofgem's DSO incentive guidance to set out the associated impacts on carbon emissions, we also report the amount (in £s terms) of overall wholesale market cost savings that relate to avoided carbon costs. This we estimate by:

- We calculate the portion of the CCGT's variable operating costs that is carbon cost.
- To calculate future carbon costs for the CCGT, we calculate the kg of CO2 emissions per MWh generated by the CCGT based on assumptions about CCGT efficiency and fuel carbon content published by DESNZ.[50]

49 We assume that batteries can discharge for four hours on average, have 80% usable capacity relative to nameplate capacity, lose 15% of energy consumed due to charging/discharging inefficiency, and make 1 round-trip per day. Based on these assumptions, we calculate that the accelerated connection of a battery storage asset displaces approximately 1,000MWh of CCGT generation p.a.. DESNZ (2018) *Storage cost and technical assumptions summary document*

50 DESNZ (November 2023) *Electricity Generation Costs 2023 Annex B: Example levelized cost of electricity (LCOE) calculator*.

- We then apply results of DESNZ's modelling of future traded carbon values in the UK Emission Trading Scheme to estimate the carbon costs (valued at market prices) paid by the CCGT per MWh of generation.[51]

As a final step we deduct the higher **capital expenditure costs** associated with generation/storage/demand-side assets connecting (and therefore being built) sooner. For generation and storage assets, we apply technology-specific estimates of the capital expenditure required per MW of capacity and calculate the time-value associated with accelerating this investment assuming technology-specific cost of capital requirements.[52]

Step 3: Estimating avoided network reinforcement cost

We use the Common Evaluation Methodology (CEM) calculations to calculate the present value of the reinforcement costs that are avoided, compared to the counterfactual.

This is based on SPEN's estimates of the following, for each connection contracted in 2024/25:

- The expected actual energisation date and assumed counterfactual connection date; and
- the expected actual reinforcement and assumed counterfactual reinforcement.

We note an important assumption underpinning the calculations, namely that SPEN assumes that reinforcement costs are entirely avoided in the factual, or in other words, SPEN does not envisage needing to reinforce in these areas in the future if this connection does not go ahead. This is based upon current known reinforcement plans.

Step 4: Estimating the potential wider economic benefits

In addition to modelling the benefits of connecting **generation and storage** assets sooner (see Step 2), we also model the benefits to the wider economy of connecting **demand-side** assets sooner.

The benefits to the wider economy of connecting non-domestic, demand-side assets can be measured by estimating the value of the goods and services produced by those assets over the period of time for which the connection has been accelerated.

Our methodology is based on estimates of Gross Value Added ('GVA') which is a measure published by the ONS that measures the total value of the goods and services that an economy produces, less the cost of all inputs and raw materials used in their production.

We apply the following methodology:

51 DESNZ (December 2024) *Traded carbon values used for modelling purposes*. Note that, in the long-run we assume carbon market values converge with the social cost of carbon, and therefore that all wider socioeconomic impacts of a CCGT's carbon emissions are internalised as variable operating costs.

52 DESNZ (November 2023) *Electricity Generation Costs 2023*

1. **Obtain GVA values for relevant sectors (£):** We obtain estimates of Gross Value Added (GVA) in £m for the industry sectors most relevant for the types of demand-side connections that have been contracted by SPEN in this regulatory year.[53]

2. **Calculate GVA per MWh:** We divide the GVA estimates by the total electricity consumption of each industry sector to obtain an implied GVA per MWh of electricity consumption by an asset in that industry sector.

3. **Calculate GVA supported (£):** We then multiply the GVA per MWh (from the previous step) by the volume of electricity consumption in MWh for each asset that has been accelerated as a result of SPEN's activities.[54]

The output is an estimate of the "GVA supported" by enabling the connection sooner and represents an indication of the economic value provided to the wider economy.

Lastly, we deduct the higher **capital expenditure costs** associated with generation/storage/demand-side assets connecting (and therefore being built) sooner. For demand-side assets, estimates of the capital expenditure required to build the asset are not readily available and therefore it is not possible to directly estimate the time-value associated with accelerating the investment. We assume that the ratio of capital expenditure costs to wider economic benefits for demand-side assets is the same as the ratio of capital expenditure costs to system operating cost benefits for generation and storage assets.

Key uncertainties and limitations

There are some uncertainties regarding this methodology:

- **We assume that flexible connections avoid the need for reinforcement on an enduring basis.** SPEN assumes that reinforcement costs are entirely avoided in the factual, or in other words, SPEN does not envisage needing to reinforce in these areas in the future if this connection does not go ahead. If load growth resulted in reinforcement taking place even if these connections were *not* going ahead, the net benefits we estimate would be reduced.

- **There is inherent uncertainty around counterfactual connection dates / timelines.** To calculate the avoided reinforcement costs, we rely on SPEN's internal best estimates of i) when the asset would have been connected in the counterfactual (i.e., absent its initiatives to accelerate connections); and ii) the likelihood that a contracted connection

---

53 We take GVA estimates from the UK Office for National Statistics (https://www.ons.gov.uk/economy/grossvalueaddedgva/datasets/nominalandrealregionalgrossvalueaddedbalancedbyindustry). There is one demand-side connection, a distillery, for which ONS GVA estimates are unavailable. In this case we have adopted GVA estimates produced by Oxford Economics on behalf of the Scotch Whisky Association (https://www.scotch-whisky.org.uk/media/2170/scotch-whisky-economic-impact-report-2024.pdf)

54 The volume of electricity consumption accelerated for demand-side assets is based on i) the time period for which the connection has been accelerated; ii) the import capacity agreed in the connection contracts; iii) an indicative load profile for the asset; and iv) an assumption that 5% of consumption is subject to curtailment for flexible connections.

will progress through to actual connection. However, we recognise that there is inherent uncertainty around the exact timeframes over which each connection would have been connected if the current schemes did not exist.

- **We assume that newly connected generation & storage assets always displace a CCGT in the wholesale electricity market**. When these assets are curtailed, the curtailed volumes are replaced by an asset with operating costs similar to a CCGT. In practice, different forms of generation will be displaced at different times.

- **We do not quantitatively assess the benefits of accelerated connections for non-industrial demand assets.** We are able to obtain GVA estimates for assets contracted this year, such as a new distillery and a new packaging plant, we are not able to apply the same approach for non-industrial assets (such as housing estates). While there are important benefits to connecting non-industrial customers (e.g. housing estates, bus charging points etc), it is difficult to assign a robust quantitative value to these. For example, if SPEN's activities result in a housing estate being connected 6 months earlier, this would involve an assessment of the value to households of living in that housing 6 months earlier (compared to the assumptions about the home that the households would have lived in in the counterfactual during that period). Answering this question would require many assumptions to be made (e.g. on the counterfactual home type, the value to households of different home types etc) and therefore, on a conservative basis, we exclude these types of non-commercial asset from our benefits quantification exercise.

- **Considerable caution should be exercised when interpreting GVA estimates.** There are several limitations to this approach which may result in over-estimation of the wider economic benefits of connecting demand-side assets sooner. In particular the GVA method assumes that:

  - The inputs used in the production of goods and services by the connected demand-side assets would not otherwise be productively employed – i.e. that there is no displacement of existing economic activity as a result of accelerating the connection.

  - The demand-side asset seeking to connect will not simply seek alternative electricity supply options in the face of the delay to its connection date in the counterfactual.

  - The average GVA per MWh for the sector is representative of the GVA per MWh of the asset which is being connected to SPEN's network.

For these reasons, we attach caution to our estimates of the GVA supported by accelerating demand-side connections as indicative and report the values separately to the other benefits we estimate as result of SPEN's activities to accelerate connections.

Results

Table 13 presents the results. Overall, we estimate that SPEN's initiatives to accelerate connections of generation and storage in 2024/25 has led to a long-term net benefit to society of £542m, of which £234m comes from avoided reinforcement and £307m comes from reduced wholesale market costs.

Table 13 Benefits quantification: Enabling connections

Cumulative benefit	In-year Apr 24 – Mar 25	Rest of ED2 Apr 24 – Mar 28	Long-term Apr 24 – Dec 67
Reduced wholesale market costs	**£0m**	**£37m**	**£307m**
Of which: Avoided carbon costs	*£0m*	*£14m*	*£228m*
Avoided reinforcement costs	**£0m**	**£0m**	**£234m**
TOTAL	**£0m**	**£37m**	**£542m**

Source: Frontier Economics
Note: Avoided carbon costs are valued at UK ETS market values for carbon emissions.

In addition, we provide a view of the potential economic benefits support by SPEN's activities this year in Table 14 below. Overall, we estimate that SPEN's initiatives to accelerate connections in 2024/25 could support £1,526m of economic benefits over the long-term. However, as noted above, this is an illustrative calculation which does not account for displacement effects and so may over-estimate the overall impact of SPEN's activities.

Table 14 Benefits supported: GVA of accelerating demand-side connections

Cumulative benefit	In-year Apr 24 – Mar 25	Rest of ED2 Apr 24 – Mar 28	Long-term Apr 24 – Dec 59
Economic benefits supported	£0m	£597m	£1,526m

Source: Frontier Economics

6 Enabling capacity for customer connections, growth, and decarbonisation (part 2)

The specific activities considered as part of this activity group are summarised in the table below.

#	Activity	Qualitative link to benefits	Quantitative KPI	Quantified benefit
Enabling capacity for customer connections, growth, and decarbonisation				
Part 2				
8	Rolling out LV network monitoring and using LV network monitoring and smart meter data to improve network visibility	✓	✓	✓
9	Installing primary transformer environmental sensors	✓	✓	×
10	Improving network planning tools	✓	×	×
11	Developing and publishing DFES forecasts	✓	✓	×
12	Strategic Optimisation team activities	✓	✓	✓
13	Whole system planning activities	✓	×	×

This section is structured as follows:

- In section 6.1, we describe SPEN's activities in 2024/25.
- In section 6.2, we set out the theory of change linking these activities to societal and consumer benefits.
- In section 6.3, we describe the KPIs associated with activities to improve network visibility (activities 8 and 9) and then then set out our methodology and results for SPEN's 2024/25 activity of rolling out LV network monitors and using the data to get extra capacity from existing assets (activity 8).
- In section 6.4, we set out the KPI associated with SPEN's activity of developing and publishing DFES forecasts (activity 11).
- In section 6.5, we set out our methodology and results for quantifying the benefits of SPEN's Strategic Optimisation team activities in 2024/25 (activity 12).

6.1 SPEN's activities in 2024/25

6.1.1 Activity 8: Rolling out LV network monitors and using LV network monitoring and smart meter data to get extra capacity from existing assets

The roll out of LV monitors and use of the data they provide is an important part of increasing LV network visibility. LV monitors have a wide range of important use cases, including:

- helping DNOs to better utilise existing network capacity;
- increasing network reliability by enabling the DNO to identify potential faults and intervene before these materialise;
- incorporate LV network visibility data into network planning tools to produce more accurate forecasts of network capacity requirements (and better informed network interventions);
- helping to facilitate the use of flexibility services; and
- managing network losses.

We focus in this report on two of the core use cases of LV monitoring, relating to helping DNOs to better utilise existing network capacity (activity 8, discussed in this section) and enabling the DO to identify potential faults and intervene before these materialised (part of activity 20, discussed in section 8.1.4).

In 2024/25, SPEN has taken actions to improve its monitoring on the LV network in order to make more informed planning decisions, including:

- **Rolling out additional LV monitors, and using this data** to identify areas where SPEN can get more capacity out of existing assets.

- **Using smart meter data** to supplement voltage data from network monitors to improve the visibility of voltage levels on low-voltage networks and make improved planning decisions in relation to connections and reinforcement work. This includes accessing individual (disaggregated) smart meter data, via a DESNZ trial, for a defined period and geographical area to improve assumptions underpinning SPEN's low-voltage model, particularly in relation to LCT uptake.[55]

These activities correspond to baseline expectation 1.1.1 which states: '*DNOs to define and develop enhanced forecasting, simulation and network modelling capabilities, with processes*

---

55 When customers install LCTs, SPEN may not always be informed by customers. Without knowing this information, intervention decisions may be less efficient (as the internal network models used by SPEN will not have the full picture about where and when SPEN needs to increase capacity). While it is possible to identify LCT uptake from individual customer smart meter data, currently, public smart meter data publication is aggregated to contain a minimum of 5 households to ensure confidentiality of household energy consumption information. This trail means that SPEN has been given permission by DESNZ to get individual un-aggregated customer data for a whole town and to use this data to update SPEN's (anonymised) aggregation model, so that when the trial ends, the models will be more accurate.

in place to drive continual improvement to meet network and user needs. We expect increased monitoring equipment to be rolled out across their network where it has demonstrable net value for network planning…. DNOs should also explore all reasonable options to use data from third parties, including harnessing smart meter data subject to data sharing agreements, to improve their simulated forecasting'.

Rolling out network monitors and using smart meter data is also in line with SPEN's RIIO-ED2 Network Visibility Strategy, corresponding to baseline expectations 1.1.2 and 2.1.2.

6.1.2 Activity 9: Enhancing transformer monitoring through environmental sensors

In 2024/25 SPEN has installed moisture and temperature sensors on 33/11kV transformers, which have been identified by SPEN's network visibility, forecasting, and network assessments as being more heavily loaded. These monitors provide insights to SPEN on the health and condition of the asset. This information enables SPEN to understand how much loading (i.e. capacity) SPEN can place on these assets. This helps SPEN to:

- secure additional capacity out of existing assets safely to accommodate additional demand (e.g. LCT update) safely; and
- identify and prioritise asset interventions including the optimal time to replace the asset.

This activity also corresponds to baseline expectation 1.1.1, as set out above.

6.1.3 Activity 10: Improving network planning tools

In 2024/25 SPEN has made changes to improve two of its network planning tools:[56]

- **SPEN's EV-Up enhanced forecasting tool:** SPEN's EV-Up enhanced forecasting tool forecasts EV uptake across SPEN's customer base.
- **SPEN's Engineering Net Zero ('ENZ') Model**: SPEN's ENZ model is a power flow analysis tool forecasts the capacity needed (including where and when) to accommodate forecast growth.

Specifically, SPEN has indicated that in 2024/25 it:

- Updated the EV-Up tool to incorporate the latest actual data on EV uptake, so that the model has an updated view of where EV demand is materialising and can update forecasts accordingly. This should lead to more accurate forecasts of EV uptake, helping SPEN to make more informed and efficient network interventions.

[56] SPEN also has a Heat-Up tool which is used to forecast uptake of heat pumps, however we do not discuss this here as no major changes were introduced in 2024/25 in relation to this tool.

- Connected the ENZ model to SPEN's central connectivity model (called Network Analyse and View or 'NAVI'). NAVI provides a complete model of the network based on GIS data and is automatically updated daily based on real configuration of the network and error correction in data records, so the accuracy of the NAVI model (in terms of how closely it reflects the real network) improves over time. The ENZ model previously used an offline version of the NAVI model but is now linked directly to the 'live' version of the model, which means that the inputs into the ENZ model will be more up-to-date and reflective of the latest network data. This should lead to more accuracy when forecasting.[57]

This activity also corresponds to baseline expectation 1.1.1, as set out above.

6.1.4 Activity 11: Developing and improving accuracy of DFES forecasts

In 2024/25, SPEN has updated and published its granular DFES forecasts,[58] setting out forecasts for key demand and generation metrics out to 2050 using updated industry data relation to characteristics of socio-economic groups (Experian), central heating types (from the ONS and Scottish Government) and off-gas postcode register (from XOServe).

In addition, SPEN made the following changes to improve the accuracy of DFES forecasting:

- Refining the modelling methodology for forecasts of district heating demand and "underlying" demand to incorporate information from stakeholders (these two components, as well as demand from LCTs make up the forecasts of peak demand).
- working closely with Strategic Optimisation team to complete a detailed review of local government decarbonisation plans and incorporate these into the forecasts;
- hosting five Stakeholder Forecasting Workshops in December 2024, providing stakeholders with an opportunity to review interim results and provide future projects for inclusion in forecasts;
- working closely with several other key stakeholders, including the Liverpool City Region Combined Authority (LCRCA), North East Wales Industrial Decarbonisation Cluster (NEWID) and Forth Green Freeport to ensure that local decarbonisation plans are included in the forecasts; and
- improving operability of the DFES model (i.e. the mechanism used to run and control the core model) through the use of cloud computing, allowing inputs to be incorporated more quickly and a greater ability to perform sensitivity studies to scrutinise the results.

As well as baseline expectation 1.1.1, this activity also corresponds to baseline expectation *1.1.3: DNOs to have in place standard and effective processes for sharing network planning information with other network licensees, including the ESO, network users and other*

57 In addition, SPEN has indicated that this change is a required interim step in order to transition into a real-time platform (with future functionality to incorporate network monitoring data, smart meter data and asset risk data).

58 Both EV-Up and ENZ tools as well as DFES are used for forecasting. However, we discuss these separately since EV-Up and ENZ are used for lower voltages whereas the most granular level captured by the DFES forecasting is the 33/11kV level.

interested parties, for example to enable innovation and support the development of local authority and devolved government plans for decarbonisation.

6.1.5 Activity 12: Strategic Optimisation team activities

SPEN has a dedicated Strategic Optimisation Team that engages with local authorities and other key regional stakeholders to understand and help develop their decarbonisation plans and incorporate them within SPEN's network development plans. In 2024/25, SPEN has:

- **Supported local authorities and regional government bodies** to support the development of Local, Regional, and National Plans, including:
  - helping 40 Local Authorities and 12 Regional Government bodies develop their decarbonisation and economic growth strategies; and
  - supporting Transport Scotland, Transport for the North, and Transport for Wales develop and implement their regional transport strategies.
- **Carried out LCT optioneering for local authorities**, which includes advice on the optimal location, costs, and timescales of LCT connections. This can be done directly through the Strategic Optimisation team and also by the Local Authorities using SPEN's Local Authority Network insight Tool ('LANIT')[59] for the SPD license area. LANIT allows Local Authorities to make independent assessments of network capacity to accommodate new electric assets and reduce the time taken to develop roll-out plans.
- **Further developed the LANIT tool** this year, with the following changes:
  - adding the ability to add new connections for LCT plans;
  - running power flow analysis up to 1MVA to understand impact of connections onto the electricity network;
  - improving accuracy regarding power flow analysis and DNO reinforcement costs;
  - optimising analysis carried out on proposed new connections to provide as much insight as possible; and
  - introducing photovoltaic (PV) generation analysis up to 200kW.
- **Ensuring that local plans are informing SPEN's Distribution Future Energy Scenarios (DFES) and future network planning**. This year, all 22 LHEES (Local Heat and Energy Efficiency Strategies) in Scotland and 9 LAEPs (Local Area Energy Plans) in Wales directly feed into the 2025 DFES. In addition, SPEN has incorporated

59 See https://www.spenergynetworks.co.uk/pages/local_authority_network_insight_tool.aspx

decarbonisation plans from 3 transport bodies, 3 industrial clusters, and 9 out of 12 regional government bodies into their DFES.

This relates to expectation *1.1.3: DNOs to have in place standard and effective processes for sharing network planning information with other network licensees, including the ESO, network users and other interested parties, for example to enable innovation and support the development of local authority and devolved government plans for decarbonisation.*

6.1.6 Activity 13: Whole system planning activities

In 2024/25 SPEN has also worked with other transmission and distribution network companies and the NESO. Specifically in 2024/25, SPEN has:

- Worked with other network companies and the NESO to develop coordinated whole system solutions – for example:
    - **North-East Wales Industrial Plan (NEWID):** Developing the North-East Industrial Decarbonisation Plan (NEWID) (in collaboration with Net Zero Industry Wales, Bangor University, gas utilities, transmission operators and local industries) which sets out an actionable emissions reduction plans for specific industries;
    - **Mid Wales:** Partnering with network companies, NESO and the Welsh Government, among others, to develop efficient network whole-electricity solutions. This is being done through: weekly meetings with NGET and NGED to ensure integrated transmission and distribution solutions; technical optioneering with NGET and NGED; and carrying out evaluations of different combinations of transmission and distribution options to assess whole system solutions.
    - **Mersey Ring:** Working with Liverpool City Regional Combined Authorities (LCRCA), NGET and other stakeholders to plan upgrades to the North-South transmission network collaboratively.
    - **Edinburgh:** Partnering with SP Transmission to develop integrated transmission and distribution network plans to address Edinburgh's forecasts capacity constraints.
- Participated in work to enhance the "week 24" planning data exchange between DNO and NESO.[60] This means NESO has more accurate data about storage connected to the distribution network and helps with more efficient network planning.

This activity also corresponds to baseline expectation 1.1.3.

[60] 'Week 24' data is the planning information that DSOs are required to submit to NESO by calendar week 24 of the year. The data includes information on forecasts for demand and embedded generation.

6.2 How these activities link to benefits

6.2.1 Outputs

As a result of the activities set out in the previous section, the DNO has:

- more accurate and enhanced planning tools; and
- more and higher-quality input data to feed into these tools, both on the DNO's own networks and customers but also on the plans and requirements of other stakeholders including NESO, transmission network owners and local authorities and government bodies.

Similarly, the DNO's sharing of data and information with these parties means that the NESO, transmission network owners, local authorities and government bodies can make better informed planning decisions.

6.2.2 Outcomes

As a result of the better panning tools and more and higher quality data:

- **DNO / NESO / Transmission network owners are more accurately able to identify the 'right' solution**, to most efficiently meet current and future network requirements. The way that this will be achieved will vary on a case-by-case basis depending on what the appropriate action is (as informed by better network planning) and what these parties would have done in the counterfactual (i.e. without having the improved network plans). These parties have a variety of tools (e.g. reinforcement solutions, flexibility solutions, other innovative solutions) at their disposable, and more information and better planning should result in them being able to better able to meet customer needs at the lowest costs.

- **Local Authorities and other government bodies are able to more efficiently identify the optimal solutions for their area.** Through greater co-ordination in planning with the DNO, the process of arriving at these solutions is likely to be more efficient (saving time and resources to carry out the planning) and should also be more aligned to network needs and spare capacity (e.g. as a result of engagement with the Strategic Optimisation team, local authorities may locate assets in less constrained areas, leading to avoided reinforcement and / or acceleration of the connection).

6.2.3 Societal benefits

The DNO identifying and choosing the lowest cost pathway more often will overall lead to a net increase in societal benefits. This net benefit may come from a range of sources, depending on the specific actions taken by the DNO / Transmission owners / NESO and other stakeholders such as Local Authorities:

- **Reductions in network capital expenditure** as result of less reinforcement being undertaken. For example:
  - One possible outcome of improved network planning is that the DNO identifies areas of the network where there is spare capacity (e.g. using LV monitoring) so that network reinforcement can be deferred, leading to a reduction in network capital expenditure. This has a societal benefit as that capital can be deployed elsewhere in the interim period of deferral (i.e. there is a time value of deferring the capital expenditure).
- **Reductions in system balancing costs** from less curtailment and / or flexibility used by the DNO as a result of better forecasting and planning. There is a resulting reduction in generation operating costs such as **reduction in fuel and carbon costs** (since in-merit assets are less frequently interrupted and displaced with less efficient assets).[61]
- **Economic and private benefits of connecting demand** earlier (and associated earlier delivery of carbon emission reductions). For example:
  - One possible outcome of improved network planning is that the DNO realises that it needs to increase capacity by more than it originally expected in order to facilitate higher-than-expect growth in EVs. This could result in network capital expenditure being brought forward, but we would this would be more than offset by acceleration of the welfare gains to customers and accelerated delivery of carbon emission reductions.
  - One possible outcome of Strategic Optimisation team activities is that Local Authorities make more informed decisions about where to connect, connecting at locations with more capacity. This would lead to reductions in network capital expenditure (and / or use of flexibility), as well as earlier delivery of the economic / private benefits of connecting this demand and associated carbon benefits.
- **Reductions in the time / resources costs of LAs** in developing their LAEPS and carrying out LCT optioneering.

6.2.4 Stakeholder benefits

Various stakeholder groups will be affected by these impacts, although, in the long-term, we expect these benefits will be passed on to consumers. For example:

- Overall reductions in network capex and / or system balancing costs will initially reduce costs for the network companies and **NESO**, and ultimately flow through to the bills of domestic and I&C **customers** through lower DUoS / TNUoS / BSUoS.

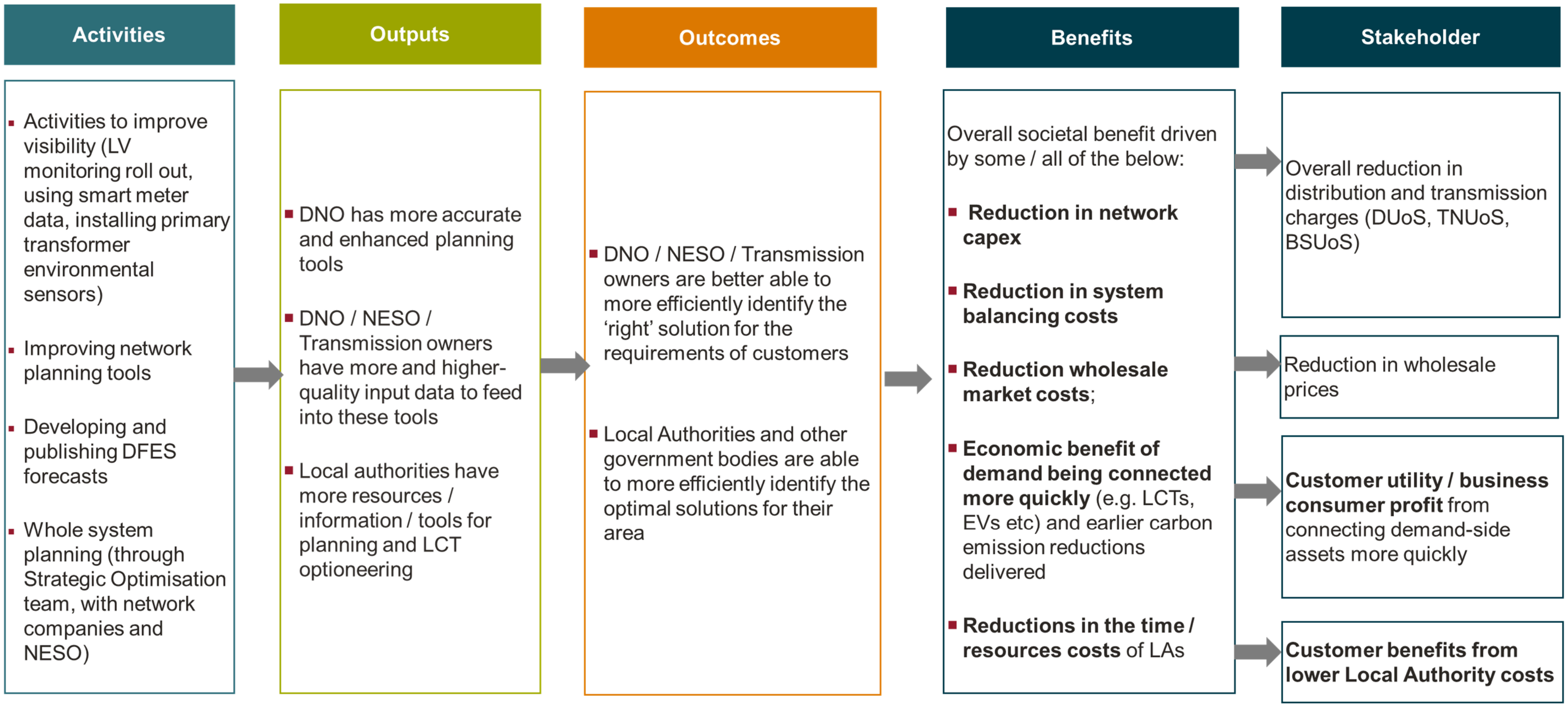
61 We note that there may also be an impact on the NESO, as customers locating near less-congested GSPs as a result of the data published by SPEN, may also reduce network reinforcement and / or system balancing costs for the NESO.

- Overall reductions in wholesale costs due to generation and storage coming onto the system sooner or with lower costs will ultimately flow through into lower wholesale **electricity costs within the bills of domestic and I&C customers.**

- The benefits of bringing demand forward will lead to welfare benefits for **commercial / industrial customers** (through higher profits) and for from **domestic customers** (through greater access to the goods and services that they value). Unlike the other types of benefits above, these would not flow through electricity bills. This includes earlier connection of Local Authority projects, from being connected in locations with more capacity.

- **Local authorities** benefit from lower resource / time costs, which will ultimately be passed on to local authority taxpayers.

Figure 12 Theory of change: Activities that enhance network planning



Source: Frontier Economics

6.3 Activities 8 – 9: Improving network visibility

In this section, we set quantitative KPIs that relate to increasing network visibility. We then describe the approach we have taken to benefits quantification, focusing specifically on the benefits associated with the rollout of LV monitors to secure extra capacity from existing assets.

6.3.1 Quantitative KPIs

We set out the KPIs relating to LV monitoring in Table 15 below.

In 2024/25 SPEN has:

- Rolled out a further 5,391 network monitors across its LV network between 1 April 2024 – 31 March 2025, compared to 1,377 LV monitors installed in 2023/24.
- Installed 2 environmental sensors at 2 sub-stations.[62] SPEN has noted that this project is at an early stage.

Table 15 KPI – Network visbility

KPI	Unit	2023/24	2024/25
Number of LV monitors installed	#	1,377	5,391
Number of environmental sensors installed	#	49	2

Source: SPEN
Note: Data for 2024/25 reflects the full period of actuals i.e. 1 April 2024 – 31 March 2025.

6.3.2 Benefits quantification

In this section we set out our methodology and results for the quantification of benefits associated with the use of **LV monitors** to secure extra capacity from existing assets. Due to insufficient data at present, we have not quantified the additional benefits that should arise from the use of environmental sensors and the use of smart metering data to improve network visibility.

Methodology

As explained earlier LV monitors have a number of use cases that will generate societal benefits. For data availability reasons, we focus our quantification on the benefits associated with the following two activities:

[62] In the future, metrics such as the proportion of substations with environmental sensors installed can be added to this KPI list.

- The first activity relates to using LV monitors to secure more capacity from existing assets and is discussed in detail in this section of the report (and is labelled as 'activity 8').

- The second activity relates to using LV monitors to identify potential faults and intervene before they materialise, avoiding interruptions to supply. This relates to SPEN's operational activities and is therefore discussed in detail in section 8, as 'activity 19'.

However, it is important to consider both benefits together when comparing against the costs of LV monitoring to identify a net benefit, so our discussion in this section refers to both activities.

We assess the benefits of further roll-out of LV monitoring in three steps:

- **Estimate benefits of deferred reinforcement:** We estimate the deferred reinforcement from using the LV monitors installed in 2024/25 to secure more capacity from existing assets.

- **Estimate benefits of avoided supply interruptions:** We estimate the expected benefits that will arise from the use of the LV network monitors installed in 2024/25 to proactively identify potential faults and intervene before they happen, avoiding supply interruptions taking place. This benefit is related to activities captured under the group "Operating a reliable and decarbonised network" and is discussed in section 8.

- **Net off costs of LV monitors**: We net off the costs to install the LV monitors in 2024/25.

We discuss each step below.

Step 1: Estimating the benefits of deferred reinforcement

We define the activity and the counterfactual in the following way:

- **Counterfactual:** Without rolling out additional LV monitors in 2024/25, SPEN does not know with confidence how much spare capacity there is on individual transformers / circuits which do not yet have LV monitors.[63]
- **Activity:** With additional LV monitors installed, SPEN can more confidently and accurately establish the spare capacity of the transformers where the LV monitors are installed. In other words, the LV monitor increases the effective usable capacity of the transformer and its connected circuits (or reduces its effective utilisation rate), since SPEN is able to better identify and safely utilise the spare capacity, while being confident that it is operating assets within their technical constraints.

We estimate the benefit in the following way:

---

63 In the absence of LV monitors, SPEN can obtain some less accurate utilisation information from maximum demand indicators (MDIs) that are manually read once a year and record peak current, which can be used to estimate annual peak demand.

- We identify the list of SPEN's transformers where LV monitors were installed in 2024/25, and the estimate of the transformers' capacity prior to the installation of the LV monitor (based on MDI readings).

- We assume that load growth would result in transformer utilisation increasing by 6.5% each year in both the counterfactual and the factual. Data from SPEN's EV-Up Heat-Up forecasting tools suggest an average compound annual growth rate of 11% over the period; however, SPEN has advised that system peak demand over RIIIO-ED2 implies a range of 2% - 4% on average. We use the mid-point of the range (i.e. 6.5%), noting that a higher load growth assumption is aligned to SPEN's strategy of targeting LV monitors in areas where transformers / circuits are expected to reach high levels of capacity by 2030.

- However, in the factual, we assume that the installation of the LV monitors in 2024/25 results in one-off reduction in the utilisation rate of the transformer. Specifically, we assume that the LV monitor allows SPEN to secure an extra 14% capacity from the existing transformer asset. [64] This assumption is based on two sources:

    - SPEN carried out an innovation study which identified that LV monitors led to an additional 8% increase in usable capacity.[65]

    - LV monitors are also a key enabler for other smart solutions such as enhanced voltage control, for which we do not quantify the benefits. SPEN has advised that based on the CBAs carried out by SPEN for RIIO-ED2, SPEN expects LV monitoring to result in an additional 15% - 20% capacity, when smart solutions are taken into account.

    - Based on the above, SPEN has advised that an appropriate range for this assumption is 8% - 20%, and we consider the mid-point of 14%.

- We assume that, at the end of the useful life of the LV monitor, SPEN is no longer able to accurately establish the spare capacity of the transformer without installing a new LV monitor. We therefore assume that the effective utilisation of the transformer reverts to that in the counterfactual at the point when the monitor reaches the end of its useful life. [66]

- Based on these assumptions, we estimate the year in which reinforcement would need to take place in the counterfactual vs the factual. We use SPEN's assumptions about the

[64] There are a small number of instances where more than one monitor is installed per transformer in 2024/25 (this applies to c. 3% of LV monitors). We currently assume that that the impact on capacity is an extra 14% regardless of whether one, two or more LV monitors are installed, effectively assuming that all monitors installed are required to deliver the assumed increase in capacity.

[65] See SPEN, December 2015, Flexible Networks Closedown Report, page 11.

[66] DESNZ assumes a 15-year lifespan for smart meters in line with the SMETS (see DESNZ (2019), Smart Meter Roll-out Cost-Benefit Analysis, page 17. LV monitors are similar in nature to smart meters, and SPEN subject matter experts agreed that a 15 year lifespan would be a reasonable assumption for these too.

typical reinforcement cost of a transformer. We calculate the total reinforcement cost across all transformers in the counterfactual and the factual, and calculate the NPV of these costs. The difference between the NPV in the factual and the counterfactual represents the saving from deferring reinforcement.[67] We note that this benefit is in gross terms, i.e. before any deductions have been made for the cost of installing the LV monitors themselves.

Step 2: Estimate benefits of avoided supply interruptions

We estimate the gross benefits arising from the avoided costs of supply interruptions, as a result of SPEN's activities to identify potential faults using LV monitors and intervene before the fault materialises. The methodology and benefits associated with this activity are discussed in Section 8.5.

Step 3: "Net off" costs of LV monitors

In step (1) and step (2) above, we obtain estimates of the gross benefits associated with activity 8 and activity 19 respectively. To obtain the net benefits, we perform the following further steps:

- As a starting point, SPEN has provided us with the unit cost associated with installing each LV monitor. We multiply this unit cost by the number of LV monitors installed by SPEN in 2024/25 to obtain the costs associated with LV monitoring rollout that are incurred in 2024/25.
- We then apply the same CEM methodology (i.e. applying capitalisation rates, cost of capital impacts, depreciation and discounting) to calculate the NPV of these LV monitoring costs.
- We then allocate these costs to the activity in step (1) and the activity in step (2) in proportion to the size of the gross benefits associated with each activity.

The output of this step is an estimate of the net benefit to society from using LV monitors to defer network capital expenditure.

Step 4: Calculate the bill impact

In the long run, any savings arising from deferred capital expenditure, relative to the reinforcement counterfactual, will flow through into the allowed revenues of the DNO and be

67 Our net benefits are estimated across the majority of transformers, then scaled up to match the final number of LV monitors installed: We calculate the expected benefit based on SPEN's data on the LV monitors installed at SPEN's transformers in 2024/25. We are not able to match all of the installed LV monitors to a specific transformer, so we calculate the benefits based on a sample of approximately 90% of the LV monitors installed in 2024//25 and scale the benefits to match the actual number of LV monitors installed in 2024/25 (5,391 monitors).

reflected in DUoS charges. We estimate the bill impacts for domestic customers using the approach set out in section 4.3.2 above.

Key uncertainties and limitations

There are some uncertainties regarding this methodology:

- **The results are highly sensitive to assumptions regarding load growth, spare capacity identified, asset lives, and reinforcement costs.** We use high-level assumptions regarding the typical expected load-growth, additional capacity that can be identified when an LV monitor is installed, the useful life of an LV monitor and 'typical' reinforcement costs that are avoided when an LV monitor is installed. These assumptions are grounded in data provided by SPEN or previous innovation studies, and stress-tested with SPEN's internal experts and senior stakeholders. It is nevertheless important to note that alternative assumptions could have material impacts on the level of benefit estimated.[68]

- **We focus on the benefits of LV monitors.** We are not aware of data available on the impact of smart metering data on network visibility and a network's subsequent ability to identify spare capacity. The estimated benefits therefore only consider the impact of LV monitors and so may be under-stated.

- **We assume that better visibility results in release of spare capacity.**[69] We assume that the installation of LV monitors results in SPEN releasing spare capacity, as this is the typical result in the majority of cases (based on SPEN's data). This is because, with more visibility, SPEN is able to safely operate the network closer to its limits. However, the installation of the LV monitor (and more accurate readings) may mean that SPEN finds that a transformer is *more* highly utilised than it expected, effectively resulting in a reduction in capacity. We do not quantify this effect – to do so would also require an additional benefit to be quantified, for example, the potential avoided loss of supply due to transformer overloading.

Results

The benefits associated with the activity of using LV monitors to secure extra capacity from existing assets is shown in Table 16 below. Overall, we estimate that SPEN's roll-out and use of LV monitoring in 2024/25 leads to a long-term net benefit to society of £9.4m (or a £2.0 one-off saving per customer in NPV terms).

68 For approximately 10% of transformers where LV monitors were installed, SPEN does not have data on the transformer utilisation prior to the installation of the LV monitor. For these transformers, we assume that their 'starting' utilisation (i.e. prior to the installation of the LV monitor) is the average of the 'starting' utilisation observed across all of the transformers where LV monitors were installed in 2024/25.

69 Diminishing returns to the roll-out of LV monitors may be expected over time, as roll-out earlier in the programme will likely focus on the transformers that are more likely to become constrained earlier.

We also note that the "in-year" benefits associated with this activity are negative. This is to be expected given the nature of the activity, which requires a one-off investment in LV monitors in-year, in order to generate benefits in future years, when reinforcement is deferred. Differences in timings between costs and benefits can result in a negative net benefit in any individual year, and should not be interpreted as suggesting that the activity is not worthwhile. It is for this reason that we recommend focusing on the long-term benefits which present a complete picture of the net benefit, accounting for *all* benefits and costs over time.

Table 16 Benefits quantification: Using LV monitoring to defer reinforcement

Cumulative benefit	In-year Apr 24 – Mar 25	Rest of ED2 Apr 24 – Mar 28	Long-term Apr 24 – Mar 85
Gross benefits of deferred reinforcement	£2.6m	£7.1m	£20.1m
Cost of LV monitors	(£3.4m)	(£4.5m)	(£10.7m)
Net benefits to society	(£0.8m)	£2.6m	£9.4m
NPV of bill savings over the long-term (£ per customer)			£2.0

Source: Frontier analysis of SPEN data

Note: Figures shown in 2024/25 prices; Benefits calculated based on all LV monitors installed between 1 April 2024 – 31 March 2025.

6.4 Activity 11: Developing and publishing DFES forecasts

6.4.1 Quantitative KPIs

SPEN tracks progress in its forecast accuracy, which is a measure of the improvements made to its DFES forecasts. This KPI is calculated using the Mean Absolute Percentage Error (MAPE) method stipulated by Ofgem in the RRP Regulatory Instructions and Guidance (RIGs) and is updated annually as part of SPEN's Regulatory Report Pack ('RRP').

SPEN has advised that its current view of forecast accuracy is 89% (measured in 2023/24, updated data is not yet available at the time of writing this report as this will be prepared and submitted later in the year

Table 17 KPI – Forecast accuracy

KPI	Unit	2024/25*
Accuracy of DFES forecasting	%	89%

Source: SPEN

*Note: *This figure was measured in 2023/24 and updated data is not yet available at the time of writing this report. We therefore use the 2023/24 stated accuracy as the current view.*

6.5 Activity 12: Strategic Optimisation team activities

In this section we set quantitative KPIs that relate to the Strategic Optimisation team activities. We then describe the approach we have taken to benefits quantification, and the resulting social NPV figures.

6.5.1 Quantitative KPIs

We set out the KPIs relating to SPEN's 2024/25 Strategic Optimisation activities below.

Table 18 KPIs – Strategic Optimisation activities

KPI	Unit	2023/24	2024/25
Engagements			
Number of LAs engaged with by SPEN	#	40	40
Proportion of LAs in SPEN's area with whom the Strategic Optimisation team has engaged	%	100%	100%
Other engagements	#	3 devolved governments, 8 regional growth deals, 3 transport partnerships, 2 industrial clusters	3 devolved governments, 12 regional growth deals, 3 transport partnerships, 3 industrial clusters

LCT optioneering			
Number of LAs supported with LCT optioneering	#	11	22
Number of sites where SPEN has conducted LCT optioneering	#	2,320	2,076
Of which: EVs	#	1,400	1,751
Of which: Heat pumps	#	800	74
Of which: PV	#	120	36

Source: SPEN data

6.5.2 Benefits quantification

Methodology

The Strategic Optimisation team's activities set out in section 6.1.5 can lead to a number of benefits such as:

- saved resource costs due to SPEN carrying out LCT optioneering across multiple local authorities; and
- customers being connected earlier and or in better locations, avoiding the need for reinforcement.

We focus on estimating the **societal benefit of saved resource costs** from SPEN carrying out LCT optioneering across multiple LAs. We define the counterfactual and activity in the following way:

- **Counterfactual:** Without the involvement of the Strategic Optimisation team and the LANIT tool, Local Authorities would still continue to carry out LCT optioneering work as they are required to develop their Local Area Energy Plans. This could require several dedicated staff members in each local authority. In addition, without SPEN's data and expertise, Local Authorities may be less efficient in this process. For example, LAs may spend time developing plans for sites that are not viable, and / or send multiple quotation requests to SPEN, resulting in higher time / resources cost to SPEN to review applications (some of which may not be viable).

- **Activity (actual):** The Strategic Optimisation team supports local authorities with LCT optioneering, which includes advice on the optimal location, costs, and timescales of LCT connections. This can be done directly by the Strategic Optimisation team and also by the Local Authorities using the LANIT tool developed by SPEN in the SPD license area. As a result, Local Authorities need fewer dedicated resources in-house to carry out this function (because it is instead carried out by SPEN across multiple LAs at once), and SPEN spends less time reviewing applications that may not be sufficiently mature or at unsuitable locations.

We estimate the benefit of avoided time spent carrying out LCT optioneering in the following way:

- **Calculate counterfactual societal costs:** We assume that in the counterfactual, the 40 LAs which SPEN supports in the actual scenario would carry out this activity in house, requiring 1 FTE each. We further assume that SPEN would require 6 FTEs spending 50% of their time reviewing applications.

- **Calculate actual societal costs:** We assume that, with the support of the Strategic Optimisation team, the FTE staffing requirement of the LAs is reduced by 75%, and the review time of SPEN is also reduced by 75%. We net off the additional cost of the Strategic Optimisation team based on 4 FTEs.

Key uncertainties and limitations

There are some uncertainties regarding this methodology:

- We use high-level assumptions, stress-tested and discussed with SPEN experts and senior stakeholders, regarding the number of FTEs required in SPEN and in LAs in the counterfactual and actual scenarios. We also use a high-level assumption on the FTE cost (which we assume is the same across LAs and SPEN), based on ONS data on Average Weekly Earnings for professional occupations.

- Benefits may be under-stated since additional benefits (e.g. acceleration of connections / avoided reinforcement due to better siting) is not quantified.

Results

The estimated benefits associated with the Strategic Optimisation team activities in 2024/25 are shown in Table 19. Overall, we estimate that these activities lead to an in-year benefit of £1.3m.

The in-year benefit of £1.3m is the same as the benefit over ED2 and in the long-term. This is because the benefits shown in the table are **cumulative** i.e. the benefits for the rest of ED2 include the in-year benefits for 2024/25, and similarly the long-term benefits also include the benefits over ED2. The nature of the Strategic Optimisation team's activities means that activity and the benefits take place in the same year (i.e. the Strategic Optimisation team provides support to Local Authorities in 2024/25 resulting in resource costs for 2024/25). There are no future benefits for ED2 and the long-term for the activities that have taken place in 2024/25, which means that the long-term benefits are equal to the in-year benefits.

Table 19 Benefits quantification: Strategic Optimisation team activities

Cumulative benefit	In-year Apr 24 – Mar 25	Rest of ED2 Apr 24 – Mar 28	Long-term Apr 24 – Mar 50
Net benefit	£1.3m	£1.3m	£1.3m

Source: Frontier calculations using SPEN data and assumptions
Note: Figures shown in 2024/25 prices

7 Providing easy access to accurate and timely data

In this section we describe the benefits associated with SPEN's activities in regulatory year 2024/25 to provide easy access to accurate and timely data. The specific activities considered as part of this activity group are summarised in the table below.

#	Activity	Qualitative link to benefits	Quantitative KPI	Quantified benefit
	Providing easy access to accurate and timely data			
14	Sharing data with stakeholders	✓	×	×
15	Improving accessibility and reach of data	✓	✓	×
16	Improving the quality of data	✓	✓	×

This section is structured as follows:

- In sub-section 7.1, we describe SPEN's activities in 2024/25.
- In sub-section 7.2, we set out the theory of change linking these activities to societal and consumer benefits.
- In section 7.3, we set out the KPIs in relation to SPEN's activities to improve accessibility and reach of its data (activity 15) and improve data quality (activity 16).

7.1.1 Activity 14: Sharing data with stakeholders

In 2024/25, SPEN has c**ontinued to share network planning datasets with stakeholders**, including the Long Term Development Statement (LTDS), Distribution Future Energy Scenarios (DFES), Network Development Plan (NDP), and Distribution Network Options Assessment (DNOA).

- In addition, SPEN has published the following 10 new datasets:
- **Planning and network development** (2 datasets): Network Development Plan; and Single Digital View.
- **Network Operations** (3 datasets): GIS Shapefiles for Local Authorities[70]; Historic Faults; and SPM Technical Limits.

[70] In response to specific demand from Local authorities, SPEN has enhanced GIS shape files (cables, poles, substations etc), to create sets of data for each local authority to enable local authorities to review the data within their own boundaries more easily. SPEN plans to expand this to overlay projection data from other data sets to enhance the insights that local authorities can gather SPEN's data sets within their own areas. The data published includes 4 data tables - SPM GIS Shapefiles – Line Assets / SPM GIS Shapefiles – Point Assets / SPD & SPT GIS Shapefiles – Line Assets / SPD & SPT GIS Shapefiles – Point Assets.

- **Market Development** (5 datasets): Aggregated Smart Meter[71]; LV Monitoring Aggregated Data[72]; Flexibility Market Prospectus; Flexibility Bids; Competitions and Registered Assets[73]; and Smart Meter Penetration data[74].

This activity relates to various activities in Ofgem's baseline expectations[75], including:

- Activity 1.1.3 which states that '*DNOs to have in place standard and effective processes for sharing network planning information with other network licensees, including the ESO, network users and other interested parties, for example to enable innovation and support the development of local authority and devolved government plans for decarbonisation'.*
- Activity 2.1.5 which states that '*DNOs to make available operational data that supports network users and other relevant stakeholders to make better decisions about how to use the network.*'
- Activity 3.1.1 which states that '*DNOs collate and publish as much relevant data and information as reasonable that will help market participants identify and value opportunities to provide network services to DNOs and take market actions that support efficient whole system outcomes'*.

7.1.2 Activity 15: Improving the accessibility and reach of shared data

- In 2024/25, SPEN has:
- **Engaged with local authorities, customers, and other stakeholders** to explore the publication of additional information and improve transparency.
- **Introduced Feature Pages to increase the accessibility of data and insights.** In response to stakeholder feedback from the 2024 DSO Event, SPEN leveraged analytics from the Open Data Portal to create feature pages[76]. These pages allow users to explore visualisations of data without needing to download or conduct their own analysis.

71 SPEN has expanded coverage for of Smart Meter data to include c. 105,000 smart meters across 1,600 transformers over two districts where SPEN has identified constraints. SPEN plans to continue to expand on this data set in conjunction with the DCC. This data includes 2 data tables: 1) SPD Aggregated Smart Consumption (Ayrshire & Clyde South) – Substation Level; and 2) SPD Aggregated Smart Consumption (Ayrshire & Clyde South) – Feeder Level.

72 To demonstrate the shift to the use of LV monitors for measuring transformer utilisation, SPEN has developed a dataset with monthly aggregated statistical data for 1,600 transformers, providing insights into LV network constraints. This data has been developed to overlap with the smart meter data to allow interoperability between these datasets. This includes 1 data table - LV Monitoring Aggregated Data.

73 SPEN has expanded its flexibility datasets to includes past competitions, bids, and registered assets. This includes 3 Data tables - Flexibility Bids / Flexibility Competitions / Flexibility Registered Assets.

74 To complement the above Aggregated Smart Meter Data, SPEN is providing data on the prevalence of smart meters on its network, this is complementary to its aggregated smart meter data and can be used to aid capacity modelling. This includes 4 data tables – Smart Meter Penetration by Postcode/ by Transformer Level / by Feeder Level / by Census Area.

75 Ofgem (2021), *RIIO-ED2 Business Plan Guidance* p77

76 Feature pages can be accessed via the open data portal on SPEN's website

Published feature pages include the ‘Single Digital View’ (a connections dashboard), the Flexibility Market Prospectus, and DFES.

- Launched a large collection of GIS shape files to provide stakeholders, such as local authorities, with better access to information about SPEN’s assets. This is in response to local authorities advising SPEN that they require GID shapefiles relevant to their geography area.

This activity relates to various activities in Ofgem’s baseline expectations,[77] including:

- Activity 3.1.2 which states that ‘*DNOs should, with stakeholder input, develop robust strategies for how they will collate and publish more helpful information, wherever possible consistently and in coordination with other network license holders, and communicate this clearly’.*
- Activity 3.1.3. which states that ‘*DNOs should regularly and actively engage with market participants to understand what data and information is helpful to support market development’.*

7.1.3 Activity 16: Improving the quality of SPEN’s data

- In 2024/25, SPEN has:
- **Made targeted data quality improvements**, including by improving the quality of data in SPEN’s Capacity Register (‘ECR’). This improvement has been measuring using the concept of ‘validity’, measuring whether values in a dataset are within the correct range or format.[78]
- **Deploying Informatica, SPEN’s data governance and quality management platform**, to improve the monitoring, control and reporting on all data assets. SPEN’s Data Governance team is working with Data Owners to define quality rules based on six quality dimensions tailored to the unique requirements of each data asset. These rules are then built into Informatica, which measures data quality and then compares actual performance against the threshold defined by the Data Owners. The resulting scores, along with detailed reports, will provide insights to help SPEN assess whether data is fit for purpose, and to develop targeted improvement plans.
- **Carried out data quality assessments** on 16 of the datasets published on their Portal (equates to 73 tables). These assessments measured datasets on the Open Data Portal against three dimensions of validity, completeness and uniqueness. SPEN is also

77 Ofgem (2021), *RIIO-ED2 Business Plan Guidance* p77

78 The Embedded Capacity Register provides information on generation and storage resources (greater than or equal to 1MW) that are connected, or accepted to connect to SPEN’s distribution network.

currently in the process of expanding these Quality Assessments to include the dimensions of timeliness, consistency and accuracy.

- **Ensured that data and outputs comply with data best practice guidelines.** This includes:
  - providing selected datasets in the standardised CIM format (which can then be used by stakeholders); and
  - developing a data best practice maturity assessment, to creates a performance benchmark performance and set targets for data best practice, alongside new data governance policies.

This activity relates to various activities in Ofgem's baseline expectations,[79] including:

- Activity 3.1.5. which states that '*DNOs should seek to ensure the information they publish is as accurate and unbiased as reasonable'.*
- Activity 2.1.5 which states that '*DNOs to make available operational data that supports network users and other relevant stakeholders to make better decisions about how to use the network. Data should be readily available in agreed and common data formats.'*

7.2 How these activities link to benefits

The logic model in Figure 13 below illustrates how these activities ultimately flow through to benefits for wider society and specific stakeholders.

We discuss elsewhere in this report how the activities of sharing data regarding flexibility (section 4.1.2), two-way data-sharing data with the TOs and NESO (section 6.1.6), and two-way data sharing with Local Authorities (section 6.1.5) lead to societal benefits. Here we focus on the activity of sharing data with other stakeholders, primarily relating to the impact for potential connecting customers. It is worth noting that the general activity of data sharing is important for increasing transparency and supporting the activities and benefits of these other logic models.

7.2.1 Outputs

With access to more and improved data, **connecting customers make better decisions** about where to locate (i.e. locating in areas with less congestion to speed up connection times) and what specification to build (i.e. because they are more aware of what capacity is available, or aware of the network constraints and opportunities to provide flexibility)

More broadly, the publication of data also results in increased transparency and trust in DNO processes and decisions, encouraging stakeholders (e.g. flexibility providers, local authorities)

79 Ofgem (2021), RIIO-ED2 Business Plan Guidance p77

to share data and participate in SPEN's processes, which supports the theory of change outlined in the other logic models above (see Figure 9 in relation to flexibility, and Figure 12 in relation to network planning activities).

7.2.2 Outcomes

Since generation / storage / demand customers are more likely to locate in areas with less congestion, this should lead to generation / storage / demand customers:

- being connected more quickly;
- connecting at sites requiring less reinforcement; and
- resulting in less requirement to use flexibility to connect these customers or to curtail users as a result of their connection.

7.2.3 Societal benefits

Connecting customers locating in areas with less congestion will lead to a net benefit to society. While net benefits should increase, the exact breakdown of this net benefit between its component parts (set out below) is uncertain and will depend on where customers would have located in the counterfactual (which would have affected the type of actions that the DNO would have taken). The net benefits will include some combination of the below:

- **Reductions in network capital expenditure** from less network reinforcement carried out.

- **Reductions in system balancing costs** from less curtailment and / or flexibility use by the DNO (because there is less need to curtail customers or to use flexibility in areas with more capacity). There is a resulting reduction in generation operating costs such as fuel and carbon costs (since in-merit assets are not interrupted and displaced with less efficient assets).[80]

- **Reductions in variable operating costs of generation** that arise from connecting generation / storage more quickly and lowered use of flexibility (which means that in-merit assets are not interrupted and displaced with less efficient assets).

- **Economic benefits** from connecting businesses and households more quickly.

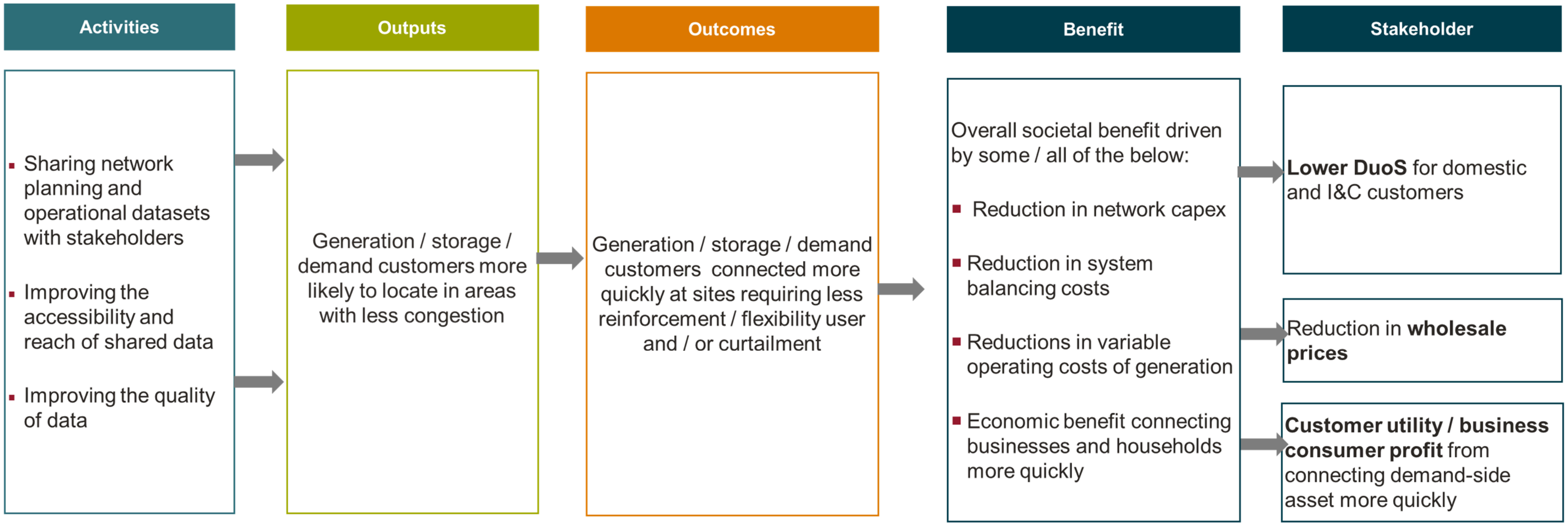
80 We note that there may also be an impact on the NESO and the transmission network, as customers locating near less-congested GSPs as a result of the data published by SPEN may also reduce transmission network reinforcement and / or system balancing costs.

7.2.4 Stakeholder benefits

Various stakeholder groups will be affected by these impacts, although, in the long-term, we expect these benefits will be passed on to consumers. For example:

- Overall reductions in network capex and / or system balancing costs will initially reduce costs for the DNO, and ultimately flow through to the bills of domestic and I&C **customers** through lower DUoS.
- Overall reductions in variable operating costs of generation and storage coming onto the system sooner and / or due to lower curtailment or with lower costs will ultimately flow through into lower wholesale **electricity costs within the bills of domestic and I&C customers.**
- The benefits of bringing demand forward will lead to welfare benefits from **domestic customers** (through greater access to the goods and services that they value). Unlike the other types of benefits above, these would not flow through electricity bills.

Figure 13 Theory of change: Providing easy access to accurate and timely data



Source: Frontier Economics

7.3 Activities 14 – 16: Quantitative KPIs

Table 20 sets out quantitative KPIs that relate to providing easy access to accurate and timely data.

In 2024/25:

- SPEN began measuring the number of users of its Open Data Portal (hence no KPI data is available for 2023/24). SPEN reports that in 2024/25 its Open Data Portal has 2,234 registered users, 1,841 users searching for data, 74 users accessing feature pages and 34,000 downloads.
- SPEN has improved the 'validity' (i.e. whether the values in a dataset are within the correct range or format) of the ECR from 48% to 84%.

Table 20 KPI – Improving accessibilty / reach and quality of data

KPI	Unit	2023/24	2024/25
Improving accessibility and reach			
Number of registered users of the Open Data Portal	#	n/a	2,234
Number of users searching for data	#	n/a	1,841
Number of users accessing feature pages	#	n/a	274
Number of downloads	#	n/a	34,000
Improving quality of data			
Validity of ECR	%	48%	84%

Source: SPEN data
Note: Data covers the full regulatory year.

8 Operating a reliable and decarbonised network

In this section we describe the benefits associated with SPEN’s activities in regulatory year 2024/25 to operate a reliable and decarbonised network. The specific activities considered as part of this activity group are summarised in the table below.

#	Activity	Qualitative link to benefits	Quantitative KPI	Quantified benefit
	Operating a reliable and decarbonised network			
17	Using flexibility to manage planned outages	✓	✓	✓
18	Using flexibility to manage unplanned outages during Storm Darragh	✓	✓	✓
19	Enhanced forecasting and modelling of curtailment requirements	✓	×	×
20	Improving monitoring and control of the HV / LV network	✓	✓	✓
21	Improving real-time communications and data exchange between DNO and NESO / TSO	✓	×	×
22	Developing an energy management platform	✓	×	×

This section is structured as follows:

- In section 8.1, we describe SPEN’s activities in 2024/25.
- In section 8.2, we set out the theory of change linking these activities to societal and consumer benefits.
- In section 8.3, we then set out our methodology and results for quantifying the benefits of SPEN’s 2024/25 activity of using flexibility to manage planned outages.
- In section 8.4, we then set out our methodology and results for quantifying the benefits of SPEN’s 2024/25 using flexibility to manage unplanned outages during Storm Darragh.
- In section 8.5, we then set out our methodology and results for quantifying the benefits of SPEN’s 2024/25 activity to improve monitoring and control of the HV/ LV network.

8.1 SPEN's activities in 2024/25

8.1.1 Activity 17: Using flexibility to manage planned outages

Activity 1 described the benefits of flexibility contracted to defer network reinforcement, which takes place as part of strategic network planning. However SPEN also procures flexibility for operational purposes, including to provide additional network security during **planned** outages.

During periods of planned outages, the network has less resilience, since parts of the network are offline to allow the required work to take place. This means that customers are more at risk of an interruption than usual, and if a fault were to occur during this period, customers would be more likely to lose supplies than in other periods. SPEN has procured flexibility services so that if a fault were to occur, the flexibility services would be used to avoid or reduce loss of supply.

This activity relates to activity 1.1.4 in Ofgem's baseline expectations, which states '*DNOs to have in place transparent and robust processes for identifying and assessing options to resolve network needs, using competition where efficient*' and '*DNOs should consider flexibility and promoting energy efficiency in addition to innovative use of existing network assets and traditional reinforcement*'.[81]

8.1.2 Activity 18: Using flexibility to manage unplanned outages during Storm Darragh

On an ongoing basis, SPEN also procures flexibility for operational purposes to restore network supplies when there is an **unplanned** outage. One recent example of this was SPEN's use of flexibility provided by the Rheidol hydro power station to restore power following recent damage to the network inflicted by Storm Darragh.

This activity relates to baseline activity 1.1.4 as set out above.

8.1.3 Activity 19: Enhanced forecasting and modelling of curtailment requirements

For RIIO-ED2, SPEN developed a near-time Predictive Analytics for Energy ('PRAE') forecasting platform which provides demand and generation forecasts. It is used by SPEN over two timeframes:

- **Up to four day ahead forecasts:** The tool forecasts demand and generation forecasts for up to four days ahead. These short-term forecasts are important to take account of the impact that weather has on the network power follows and take appropriate operational

81 Ofgem (2021), RIIO-ED2 Business Plan Guidance p77

actions. For example, without this forecasting information, during a planned outage, the control room might make more conservative assumptions, resulting in a generator being curtailed. With better forecasts, the control room can safely use more spare capacity on the network, reducing customer curtailment and increasing the level of low carbon generation on the system.

- **Monthly / annual forecasts:** The tool is used by the control room to plan operational actions such as flexibility services utilisation during planned maintenance outages over the longer term.

In 2024/25 SPEN has advised that it has increased its use of the PRAE T-4 tool which provides forecasts for up to four days ahead, by using it more frequently to identify opportunities where spare capacity can be safely utilised in congested areas.

This activity supports various activities in Ofgem's baseline expectations such as:

- Activity 1.1.1 which states '*DNOs to define and develop enhanced forecasting, simulation and network modelling capabilities, with processes in place to drive continual improvement to meet network and user needs'*; and
- Activity 2.2.1 which states '*DNOs to have and regularly review a decision-making framework for when DER are instructed to dispatch in real-time'*. [82]

8.1.4 Activity 20: Improving monitoring and control of the HV / LV network

In 2024/25 SPEN has undertaken the following two sub-activities activity to improve its control of the HV/ LV network:

- **Rollout of additional Network Controllable Points across the HV network.** A Network Controllable Point is an installed network asset which enables the DNO to monitor and control power flows on the network remotely, thus reducing the number and duration of interruptions to customer electricity supply.
- **Using LV monitor data to identify potential faults and intervene before they happen**. SPEN has developed advanced fault detection algorithms which use data from smart meters and LV network monitors to predict faults before they happen. This means that SPEN can identify potential faults and fix these on a planned basis rather than fixing them once the faults have manifested and customers have lost supply.

These activities support various activities in Ofgem's baseline expectations[83], including:

82 Ofgem (2021), *RIIO-ED2 Business Plan Guidance* page 77.

83 Ofgem (2021), *RIIO-ED2 Business Plan Guidance* page 77.

- Activity 1.1.1 which states '*DNOs to define and develop enhanced forecasting, simulation and network modelling capabilities, with processes in place to drive continual improvement to meet network and user needs'*;
- Activity 2.1.2 which refers to the DNO's visibility strategy and the use of network data for operational decisions.

8.1.5 Activity 21: Improving real-time communications and data exchange between DNO and NESO / TSO

In 2024/25 SPEN has taken the following actions to improve real-time communication and data exchange between DNO and NESO/TSO.

- SPEN has implemented an Inter-Control Centre Communications 'ICCP' link (now live) between SPD and NESO control room; and
- Development of communication links between NESO and DNO control rooms will support the exchange of information about constraints on both the transmission and distribution networks. This may ultimately reduce instances of conflict between instructions from DSO and NESO (e.g., NESO instructing an embedded asset to turn-up via the Balancing Mechanism for energy balancing reasons, and DNO curtailing other embedded assets on the same part of the network to manage local congestion).

This activity relates to various activities in Ofgem's baseline expectations,[84] including:

- Activity 2.1.1 which states that '*DNOs to improve network visibility and identification and sharing of operability constraints, including publishing this data to help avoid conflicting actions being taken by other network and system operators'*.
- Activity 2.1.3 which states that '*DNOs to provide the ESO with information across timelines about the DER it is planning to dispatch'*
- Activity 2.1.5 which states that '*DNOs to make available operational data that support network users and other relevant stakeholders to make better decisions about how to use the network'.*

8.1.6 Activity 22: Developing an energy management platform

In 2024/25, SPEN has made progress to design an Energy Management Platform.

SPEN is developing an Energy Management Platform to support SPEN's control room with operational actions to manage the distribution network. This will allow SPEN to more effectively and efficiently conduct operational actions, including managing voltage control of

84 Ofgem (2021), RIIO-ED2 Business Plan Guidance p77

the network, communicating with PicloFlex dispatch, and communicating with DERs to manage constraints.

SPEN is currently tendering for this Energy Management Platform and so we do not quantify benefits associated with this activity.

This activity relates to activity 2.2.4

in Ofgem's baseline expectations, which states '*DNOs to develop efficient, scalable instruction infrastructure and avoided proprietary systems*.[85]

8.2 How these activities link to benefits

The logic model in Figure 14 below illustrates how these activities ultimately flow through to benefits for wider society and specific stakeholders.

8.2.1 Outputs

The activities set out in the previous section have a wide variety of effects, but broadly lead to the following two types of output:

- The DNO / NESO has an **improved set of tools to operate the network and better visibility** over which tool is the lowest-cost solution to address a particular constraint. For example:
    - The installation of network controllable points gives the DNO ability to more quickly and efficiently precisely reconfigure the network when required, to avoid or reduce unplanned interruptions to supply.
    - Use of fault detection algorithms and LV monitor data gives the DNO better visibility over the low-voltage network to allow the DNO to anticipate faults on the network and identify faults faster when they arise, again avoiding or reducing the impact of unplanned supply interruptions.
    - Enhanced forecasting capabilities in operational timescales enable the DNO / NESO to better anticipate network congestion, and consequently determine the actions required to manage this congestion. This should reduce the number of occasions where errors in DNO forecasts lead to redundant curtailment.
- There are **fewer conflicts in DNO / NESO operational actions**. For example the development of communication links between NESO and DNO control rooms supports the exchange of information about constraints on both the transmission and distribution

85 Ofgem (2021), [RIIO-ED2 Business Plan Guidance](#) p77

networks. This should reduce instances of conflict between instructions from DNO and NESO and leading to more efficient dispatch decisions overall.

8.2.2 Outcomes

The DNO and NESO are able to identify and use the lowest-cost intervention more often, including:

- The DNO is more able to **predict faults** and take actions **to reduce the number and duration of supply interruptions**;
- the DNO is able to more efficiently **use flexibility** to **reduce the number and duration of supply interruptions**;
- the DNO and NESO are able to **dispatch flexibility more efficiently**; and
- the DNO and NESO is able to use **curtailment more efficiently**.

8.2.3 Societal benefits

The DNO / NESO identifying and choosing more efficient operational interventions will overall lead to net societal benefits. While we expect net benefits to increase, the exact breakdown of this net benefit between its component parts (set out below) is uncertain and will depend on the specific actions taken by the DNO / NESO:

- **Private / economic benefit of reduced interruptions to electricity supply for DNO customers**, which can be captured at the Value of Lost Load[86]; and

- **Reductions in system balancing costs** from more efficient use of curtailment and flexibility by the DNO and NESO and the resulting reduction in generation operating costs such as fuel and carbon costs.

86 Value of Lost Load (VoLL) represents the value that electricity users attribute to security of electricity supply and the estimates can be used to provide a price signal about the adequate level of security of supply in GB. (see Ofgem (2018) Targeting Charging Review Glossary, page 6)

8.2.4 Stakeholder benefits

Various stakeholder groups will be affected by these impacts, although, in the long-term, we expect these benefits will be passed on to consumers. For example:

- Overall reductions in system balancing costs will initially reduce costs for the DNO and **NESO**, and ultimately flow through to the bills of domestic and I&C **customers** through lower DUoS / BSUoS.
- Overall reductions in variable costs of generation due to lower curtailment will ultimately flow through into lower wholesale **electricity costs within the bills of domestic and I&C customers.**
- The benefits of **reduced interruptions to electricity supply** will lead to wider economic benefits outside of the electricity system. Benefits to **domestic customers** could include avoided inconvenience/cost associated with interruption of power to domestic low carbon technologies - such as charging for EVs or heat pumps. [87] Benefits to **non-domestic/commercial customers** could include avoided costs/lost profits associated with interruption to industrial production processes.

[87] This cost will become increasingly more important with increased electrification.

Figure 14 Theory of change: Activities to operate a reliable and decarbonised network

Activities

- Procuring flexibility to manage planned and unplanned outages
- Enhanced forecasting and modelling of curtailment requirements
- Improving monitoring and control of the LV network
- Improving real-time communications and data exchange between DNO and NESO / TSO
- Developing an energy management platform

Outputs

- DNO / NESO have more and improved set of tools to operate the network, and improved visibility and decision-making over which tool is the lowest-cost solution including:
  - Better forecasting capabilities to better anticipate network congestion
  - Using flexibility to manage outages
  - Ability to reconfigure the network to avoid or reduce interruptions to supply
  - Use fault detection algorithms to anticipate and prevent faults
- Fewer conflicts in DNO/ NESO operational actions

Outcomes

- DNO / NESO able to identify and use the lowest-cost intervention more often leading to:
  - More efficient dispatch of flexibility
  - More efficient use of curtailment
- Fewer / shorter interruptions to supply through proactive fault management and / or use of flexibility

Benefits

Overall societal benefit driven by some / all of the below:

- Reductions in system balancing costs from more efficient use of curtailment and flexibility by the DNO and NESO
- Private / economic benefit of reduced interruptions to electricity supply for DSO customers

Stakeholder

Overall reduction in BSUoS and DUoS

Lower wholesale prices from lower curtailment

Consumer benefits from reduced interruptions to supply:

- Households experience reduced inconvenience
- Commercial/ industrial customers experience increased profit

Source: Frontier Economics

8.3 Activity 18: Using flexibility to manage planned outages

In this section we set quantitative KPIs that relate to using flexibility to manage unplanned outages. We then describe the approach we have taken to benefits quantification.

8.3.1 Quantitative KPIs

Table 21 KPIs: Flexibility to manage planned outages

KPI	Unit	2023/24	2024/25
Number of sites for which SPEN has identified flexibility could provide value and **tendered** for flexibility	#	15	16
Number of sites for which SPEN has successfully **contracted** flexibility	#	13	16
Flexibility **tendered** within the year across **all** sites, for delivery in any year (sum of monthly peak capacities)	MW	28.9	146
Flexibility **contracted** within the year across **all** sites, for delivery in any year (sum of monthly peak capacities)	MW	28.0	24
Flexibility being delivered within the year	MWh	48.4	320

Source: SPEN Auction data

Note: The 2024/25 period does not represent the full regulatory year, as data was only available up to and including January 2025 at the time of analysis.

8.3.2 Benefits quantification

Methodology

Flexibility is procured during planned outages to mitigate the risk that an unplanned failure of a further asset leads to a loss of supply. This flexibility can either involve the use of alternative forms of supply, or managed load-shedding through demand-side response: Both reduce the power requirements on the remaining assets, and can therefore help to maintain a continuous supply of electricity to other customers.

In both scenarios, SPEN procures flexibility as 'insurance' against potential faults during a planned outage. This insurance will not be required for most planned outages, but will prevent outages and substantial costs that would occur for a small percentage of planned outages (those where there is a network fault during the planned outage).

We calculate the benefit associated with this activity in four steps:

Step 1: Define counterfactual and activity (actual)

We define the activity and the counterfactual in the following way:

- **Counterfactual:** Without flexibility procurement, if a fault occurs during a planned outage, customers experienced an unplanned interruption to their electricity supply.
- **Activity (actual)**: SPEN procures flexibility in this or previous regulatory years to manage planned outages occurring in the current regulatory year. These planned outages are scheduled in advance with a high degree of certainty, allowing SPEN to proactively secure flexibility ahead of time. Therefore, we account for the benefits only when the planned outage actually takes place. This differs from our deferred reinforcement approach, where benefits are recognized at the time of the initial flexibility contract procurement, as explained in Section 4. In the actual scenario, we assume the insurance is perfectly effective, so no additional costs from customer interruptions are incurred in the factual when the flexibility is used.

Step 2: Estimate probability of at least one fault occurring during the planned outages

Our starting point is the list of sites for which SPEN has procured flexibility to be delivered in 2024/25 when a planned outage is taking place. We first estimate the probability of at least one fault occurring during the planned outage.

This probability is based on the duration of the planned outage (we base this on the number of hours for which flexibility was contracted based on SPEN's auction data) and the probability that a fault happens per hour.[88] We base this on the probability of a fault during a planned outage at a representative substation equipped with two 33 kV transformers operating under an N-1 redundancy arrangement. In this configuration, the transformer undergoing the planned outage is backed up by a second transformer that is at risk of an unplanned outage, with assets assumed to be in average condition (classified as 'HI3' in the CNAIM). [89]

Step 3: Estimate the avoided CI societal costs

We base our measure of the societal cost of supply interruptions based on Ofgem's penalty rates for CI and CML. These values are based on the Value of Lost Load (VoLL) and reflects the total societal cost of lost supply, making it appropriate for this analysis.

We first estimate the avoided expected CI cost of a fault during a planned outage by multiplying the following:

[88] We calculate the probability based on a Poisson distribution as we assume that faults occur independently with a constant hourly probability.

[89] Ofgem (April 2021), DNO Common Network Asset Indices Methodology (CNAIM), see table 235

- the **probability** of a fault occurring (from step (1));
- the **cost per fault** (we use the CI cost from the Ofgem RIIO-ED2 templates, which report a value of £18.57 per customer,[90] which translates to £24.62 per customers interrupted);
- the **number of customers affected** by a typical interruption. The number of customers affected is estimated by dividing the maximum transformer demand capacity (which is assumed to be 15kV[91]) by the average effective peak demand per customer (which is assumed to be 1 kV[92]).

Step 4: Estimate the avoided CML societal costs

We estimate the avoided CML cost of a fault during a planned outage in a similar way, by multiplying the following:

- the probability of a fault (from step 1);
- the number of customers at risk (from step 2);
- the expected fault duration (which we assume is 2 hours based on CNAIM[93]); and
- Ofgem's CML cost (we use the CML cost from the Ofgem RIIO-ED2 templates, which report a value of £0.45 minutes lost in 2020/21 prices,[94] which translates to £0.60 per minutes lost in 2024/25 prices).

Step 5: Net off SPEN's actual cost of procuring flexibility

We calculate the cost of using flexibility based on SPEN's auction data. Since we assume the insurance is perfectly effective, no additional costs from customer interruptions are incurred in the factual scenario. Therefore, the total costs include only the auction-derived flexibility expenditure:

- The availability payments SPEN makes to flexibility providers to procure services that are used to manage planned outages, regardless of whether a fault occurs.

- The expected utilisation payment, estimated by multiplying the probability of at least one fault occurring and by the fault duration (from the calculations above). This reflects the expected cost of activating flexibility when a fault occurs.

90 Ofgem (October 2021), RIIO-ED2 Cost Benefit Analysis Template, see "Fixed Data" tab.

91 Ofgem (April 2021), DNO Common Network Asset Indices Methodology (CNAIM), see table 235

92 This assumption is based on typical network planning values used by DNOs, as referenced in sources such as Pimm et al. (2018). The potential for peak shaving on low voltage distribution networks using electricity storage - ScienceDirect Figure 4

93 Ofgem (April 2021), DNO Common Network Asset Indices Methodology, see table 235

94 Ofgem (October 2021), RIIO-ED2 Cost Benefit Analysis Template, see "Fixed Data" tab.

Step 6: Calculate net benefit

The net benefit of SPEN's activity to procure flexibility to be utilised this year is calculated as the difference between:

- the total CML and CI cost that SPEN would face in the counterfactual scenario (steps 3 and 4); less
- the actual total cost of contracted flexibility used to manage planned outages during the same year (step 5).

Key uncertainties and limitations

There are some uncertainties regarding this methodology:

- Flexibility procurement during planned outages occurs across various sites and different segments of the network. In reality outages at these locations will result in different fault risks and consequences, depending on the type of network assets involved. However, estimating these potential costs individually for each site would involve assessing asset conditions, fault probabilities, and affected customer counts. We have adopted an alternative, simplified approach, where we use a *representative* scenario designed to represent a typical site and capture average cost exposure across all locations where flexibility procurement serves as security against planned outages.

- In the actual scenario, we assume that the insurance is perfectly effective, resulting in no additional costs from customer interruptions. In reality, there is still a possibility that some customers' supply may be interrupted, but SPEN's flexibility team confirmed that this is a reasonable assumption for the purpose of this analysis.

Results

Table 22 presents the results of our analysis on the benefits of using flexibility to manage planned outages during the 2024/25 regulatory year. We estimate the total net benefit for the year at £4.4 million.

When interpreting this value it is important to note that this value remains constant across longer-term projections, as it is specifically tied to the planned outages that occurred and were managed using flexibility in 2024/25. This does not imply that the total cumulative benefit from SPEN's actions over the RIIO-ED2 period will remain at £4.4 million. On the contrary, the cumulative benefit is expected to increase each year as SPEN continues to procure and deploy flexibility to manage additional outages. However, those future benefits are linked to actions taken in subsequent years and are therefore not included in the 2024/25 assessment.

We do not quantify the impact on domestic customer bills. The benefit of flexibility in this context is delivered directly to customers through reduced interruptions, rather than through reductions in bill charges.

Table 22 Benefits quantification: Using flexibility to manage planned outages

Cumulative benefit	In-year Apr 24 – Mar 25	Rest of ED2 Apr 24 – Mar 28	Long-term Apr 24 – Mar 85
Gross benefits of managing planned outages	£5.0m	£5.0m	£5.0m
Cost of flexibility	(£0.6m)	(£0.6m)	(£0.6m)
Net benefits to society	£4.4m	£4.4m	£4.4m

Source: Frontier analysis of SPEN data

Note: Figures shown in 2024/25 prices, and are based on proportionally scaled outturn data from April 2024 to January 2025, to account for the unavailability of February and March 2025 data at the time of analysis

8.4 Activity 19: Using flexibility to manage unplanned outages during Storm Darragh

The risk of a fault occurring during a planned outage can be estimated, as planned outages take place regularly. For this reason, in the previous section we calculated the expected benefits of flexibility based on a known and recurring level of risk.

While a similar approach could be considered for unplanned outages, the associated CI and CML are typically driven by rare, high-impact events (such as extreme-weather events) that do not occur every year but can affect a large number of customers when they do. As such, a benefits calculation based on average or expected outage rates is unlikely to reflect the actual value experienced by customers in any given year.

To address this, we have taken a different approach for assessing flexibility used to manage unplanned outages. Our analysis is based on the actual deployment and impact of flexibility during 2024/25. In this regulatory year, SPEN prioritised the procurement of flexibility in Mid-Wales to mitigate the effects of unplanned outages during extreme weather events.

The configuration of the distribution network in Mid-Wales makes it especially vulnerable to such events. Extensive overhead line networks at both 11kV and 33kV are exposed to environmental hazards such as high winds, falling trees, and storm-related damage. The rural nature of the region also complicates restoration efforts, as access to damaged infrastructure can be delayed by flooding or obstructed routes.

In 2024/25, flexibility procured to manage unplanned outages in Mid-Wales was used to support the restoration of customer supply during Storm Darragh. Based on the success of using flexibility in this particular case, SPEN plans to expand flexibility procurement for unplanned outage mitigation in similarly exposed areas across the network as part of its 2025/26 strategy.

In this section, we outline our methodology for quantifying the benefits of deploying this flexibility and present the associated results.

8.4.1 Quantitative KPIs

We present a single KPI for this activity, which relates to the peak MW of flexibility that was contracted *and subsequently utilised* to manage planned outages. For 2024/25 this is 20MW, reflecting the contracted capacity of Rheidol power station which was used to provide support during Storm Darragh.

Please note that the units here are different from those given in Table 21 (relating to planned outages) which considers the sum of monthly peak capacities contracted, regardless of utilisation. This reflects the difference in the approach to calculating net benefits described above: We consider the *ex-ante* net benefits of flexibility to manage planned outages, but the *ex-post* net benefits of flexibility to manage unplanned outages.

Table 23 KPIs: Flexibility to manage unplanned outages

KPI	Unit	2023/24	2024/25
Operational Flexibility utilised within the year across all sites	MW	0	20

Source: SPEN

8.4.2 Benefits quantification

Methodology

We calculate the benefit associated with this activity in four steps:

Step 1: Define counterfactual and activity

Based on the background outlined above, the actual and counterfactual scenarios are defined as follows:

- **Activity (actual):** SEPN deploys flexibility services so that a portion of customers that were interrupted during the storm are restored and stabilised earlier.
- **Counterfactual:** The same customers are reconnected under business-as-usual conditions, without flexibility, resulting in longer restoration times.

Step 2: Estimate cost of outages

Estimating the cost of outages in each scenario requires a number of assumptions:

- **Number of customers:** We use SPEN's data on the approximately 15,000 customers had their supply restored earlier due to the availability of flexibility during Storm Darragh.
- **Reduction in restoration time:** SPEN estimates that flexibility allowed these customers to be reconnected, on average, 4 hours sooner than would have been possible without it.
- **Cost of CML:** The cost per customer minute lost (CML) is sourced from Ofgem's Cost-Benefit Analysis guidelines, as described above.

Based on these assumptions, we estimate the total avoided cost (i.e. the reduction in the total cost of CML). It is estimated by multiplying the number of customers restored earlier, the average reduction in outage duration, and the societal cost of CML. We note that while CI costs are still incurred, they are present in both the actual and counterfactual scenarios and therefore cancel out.

Step 3: Estimate cost of procuring flexibility

The actual availability and utilisation payments for the relevant flexibility services are taken directly from SPEN's auction data.

Step 4: Estimate net benefit

The total net benefit is calculated as the difference between the total avoided cost (from point 5) and the total cost of flexibility used during Storm Darragh (from point 3).

Key uncertainties and limitations

- The findings are highly specific to this particular event and location, which limits their broader applicability across SPEN's network or over longer time horizons.
- In particular, there is no reliable way to predict whether a storm of similar magnitude will impact SPEN's network again, or how frequently such events might occur in the future.
- Secondly, the assessment has a strong regional focus, being based solely on events in Wales. This is because SPEN has prioritised procuring this type of flexibility in areas that are particularly vulnerable to these types of events. At the moment, this type of flexibility is only relevant to Rheidol (and gives the associated benefit figure relating to Storm Darragh), but SPEN intends to extend this sort of activity in future.

Results

Table 24 presents the results of our analysis of the benefits derived from deploying incremental flexibility to manage unplanned outages during 2024/25. We estimate a total net benefit of £2.1m for the year. As this benefit relates directly to managing unplanned outages that occurred during Storm Darragh in 2024, it remains constant in longer-term projections.

As explained above, the nature of the activity of dispatching flexibility means that the activity and the benefit both happen in the same year, i.e. 2024/25. This means that the benefit across all time horizons is the same as the in-year benefit (because there are no further benefits in future years realised from this year's actions). As and when SPEN dispatches flexibility to manage unplanned outages in future years, the associated benefits will be recorded in the future submissions, in the year in which those activities take place.

We have not quantified any direct impact on domestic customer bills. This is because, in the context of managing unplanned outages, flexibility delivers benefits directly to customers through reduced interruption durations, rather than through lower electricity charges.

Table 24 Benefits quantification: Using flexibility to manage unplanned outages during Storm Darragh

Cumulative benefit	**In-year** **Apr 24 – Mar 25**	**Rest of ED2** **Apr 24 – Mar 28**	**Long-term** **Apr 24 – Mar 85**
Gross benefits of managing unplanned outages	£2.16m	£2.16m	£2.16m
Cost of flexibility	(£0.04m)	(£0.04m)	(£0.04m)
Net benefits to society	£2.12m	£2.12m	£2.12m

Source: Frontier analysis of SPEN data
Note: Figures shown in 2024/25 prices

8.5 Activity 20: Improving monitoring and control of the LV network

In this section we set quantitative KPIs that relate to improving monitoring and control of the LV network. We then describe the approach we have taken to benefits quantification, focusing specifically on the benefits from using data from LV monitors installed in 2024/25, combined with fault detection algorithms, to identify potential faults and intervene before they happen.

8.5.1 Quantitative KPIs

KPIs relating to the roll out of LV monitors is discussed in section 6.3.1. here, we set out the KPI relating to the roll out of network controllable points.

In 2024/25, SPEN has:

- rolled out 1,380 network controllable points on the HV network in 2024/25, compared to 1,115 in 2023/24;
- proactively identified 154 potential faults, of which 84% were proactively repaired in 2024/25 (for the remaining 16%, the repair plan is intended to be carried out in 2025/26). This is in comparison to 75 potential faults being identified in 2023/24 with all addressed proactively within that same year.

Table 25 KPI – Improving monitoring and control of the HV / LV network

KPI	Unit	2023/24	2024/25
Network Controllable Points			
Number of network controllable points installed in 2024/25	#	1,115	1,380
Of which: New network controllable points	#	673	853
Of which: Modernisation of legacy units	#	442	527
Faults proactive detection and repair			
Number of potential faults identified in 2024/25	#	75	154
Number of potential faults repaired	# / %	75 (100%)	129 (84%)
Number of faults with repair plan carried over into 2025/26	# / %	0 (0%)	25 (16%)

Source: SPEN data
Note: Data represents actuals over the full regulatory year, i.e. 1 April 2024 – 31 March 2025.

8.5.2 Benefits quantification

In this section we set out our methodology and results for the benefits associated with the use of **LV monitors** to identify potential faults and intervene before they arise (i.e. **activity 19**). Due to insufficient data at present, we have not quantified the benefits arising specifically from smart metering in identifying potential faults or the benefits of rolling out further network controllable points.

The quantification for this benefit is related to the calculations associated with using LV monitors to secure more capacity from existing assets (referred to as activity 8, discussed in section 6.1.1) since both activities share the same costs (i.e. the costs of installing LV monitors). This is discussed further in our methodology outlined below.

We estimate the benefits in 7 steps:

Step 1: Define the counterfactual and activity (actual)

We define the activity (actual) and the counterfactual in the following way:

- **Counterfactual:** Without rolling out additional LV monitors in 2024/25, SPEN does not have data from these monitors to incorporate into its fault detection algorithms and so cannot identify faults proactively. When these faults materialise, this will lead to a loss of supply for customers (i.e. CML / CI costs).

- **Activity (actual):** With additional LV monitors installed, SPEN can include this data in its fault detection algorithms, leading to more instances of SPEN identifying potential faults, and intervening before these faults materialise, avoiding the loss of supply to customers.

Step 2: Estimate the probability that an LV monitor leads to the identification and avoidance of a fault.

We estimate the probability that an LV monitor leads to the identification and avoidance of a fault in the following way:

- We assume that the probability that a monitor leads to the identification of a fault in a given year is 2%, based on the number of potential faults identified by SPEN as a result of LV monitor data, divided by the total stock of LV monitors in 2024/25 (including the monitors rolled out in 2024/25).

- Based on input from SPEN, we also assume that SPEN can intervene before the fault materialises 50% of the time.

- Applying these two assumptions together, we estimate that a given LV monitor leads to the identification and avoidance of a fault **1% of the time in any given year.**

Step 3: We calculate the avoided CML and CI cost per fault

As explained above, the CML and CI cost reflects the societal value of disruption to customers from supply interruptions. We estimate the avoided CML and CI costs in the following way:

- We use the CML and CI cost from the Ofgem RIIO-ED2 templates, adjusted to 2024/25 prices. We also assume that the customer impact value of a planned interruption is half of that of an unplanned interruption, to reflect the lower disruption to customers of a planned interruption (i.e. customers are warned in advance), in line with Ofgem's valuations of interruptions for RIIO-ED2.[95]

- We assume a typical interruption of 2.5 hours with 30 customers affected (assumptions provided by SPEN).

- This gives a CML cost of £1,351 per fault (CML penalty of £0.6 per minute lost × 50% × 2.5 hour interruption × 30 customers affected) and a CI cost of £369 per fault (CI penalty of £25 per customer interrupted × 50% × 30 customers affected).

The output of this step is a combined **CML / CI penalty of £1,720 per fault.**

95 Ofgem (November 2022), RIIO-ED2 Final Determinations Core Methodology Document, paragraph 6.127.

Step 4: Estimate avoided CML and CI cost per year per monitor

Combining step (2) and (3) suggests that an LV monitor would lead to an avoided cost of £17 per year (i.e. 1% probability that the monitor leads to the identification and correct of the fault × £1,720 cost avoided).

Step 5: Estimate avoided cost per year across all monitors

We calculate the expected avoided costs per year across all monitors installed in 2024/25. We multiply the benefit from step (4) by the number of LV monitors installed in 2024/25 (i.e. 5,391 monitors) which gives an annual benefit of c. £81,000 per year.

Step 6: Estimate NPV of avoided cost across all monitors over time

We then calculate the NPV of the benefits over the lifetime of the monitors. Specifically, we assume that these benefits apply in each year of the LV monitor's useful life (i.e. over a period of 15 years from the 2024/25 installation year) and calculate the NPV of this stream of benefits.

Step 7: Net off the costs of LV monitors

The output of Step 6 is an estimate of the gross benefits associated the activity. To obtain the net benefits, we then deduct the costs of LV monitoring that have been allocated to this activity (as explained in section 6.3.2).

The output of this step is an estimate of the net benefit to society from using LV monitors to identify and correct potential faults before they materialise.

Key uncertainties and limitations

There are some uncertainties regarding this methodology:

- **Likelihood of faults occurring:** Two key assumptions underpinning our methodology are that: 1) 100% of the faults that are proactively identified would ultimately have led to a loss of CML / CI within a year if SPEN had not proactively identified them; and 2) SPEN is able to intervene before the fault occurs 50% of the time. Experts at SPEN have confirmed that these assumptions are reasonable.

- **Treatment of repair costs:** We assume that the costs of proactive and reactive repairs are the same and therefore we do not account for any differences in costs in the counterfactual and actual scenario relating to repair costs. SPEN has confirmed that this is a reasonable assumption.[96]

[96] While typical proactive repair cost can be higher than a reactive repair cost, these figures are not directly comparable because typically only the 'minimum works' are done when the repair is reactive. Since there are also likely to be dis-benefits associated with carrying out 'minimum works' that we do not quantify, we instead assume that the costs for both types of repairs are similar.

- **Focus on LV monitors:** We only account for the impact of LV monitors on identifying faults (i.e. we do not take account of the benefits from smart meter data or the benefits of controllable points).

Results

Overall, we estimate that SPEN's roll-out and use of LV monitoring in 2024/25 (covering all LV monitors rolled out between 1 April 2024 – 31 March 2025) to identify potential faults and intervene before they materialise leads to a long-term net benefit to society of £0.5m (see Table 26 below).

We also note that the 'in-year' benefits associated with this activity are negative: This is expected given the nature of the activity, which requires a one-off investment in LV monitors in-year, in order to generate benefits in future years, when the LV monitor identifies potential faults. Differences in timings between costs and benefits can result in a negative net benefit in any individual year, and should not be interpreted as suggesting that the activity is not worthwhile. It is for this reason that we recommend focusing on the long-term benefits which present a complete picture of the net benefit, accounting for *all* benefits and costs over time.

We have not quantified any direct impact on domestic customer bills. This is because the activity delivers directly to customers through reduced number and duration of supply interruptions, rather than through lower electricity charges.

Table 26 Benefits quantification: Using LV monitors to identify faults

Cumulative benefit	In-year Apr 24 – Mar 25	Rest of ED2 Apr 24 – Mar 28	Long-term Apr 24 – Mar 70
Gross benefits of avoided interruptions	£0.1m	£0.3m	£1.1m
Cost of LV monitors	(£0.1m)	(£0.2m)	(£0.6m)
Net benefits to society	(0.03m)	£0.1m	£0.5m

Source: Frontier analysis of SPEN data

Note: Figures shown in 2024/25 prices. The benefits capture all LV monitors installed between 1 April 2024 – 31 March 2025. The NPV of LV monitor costs increase over time because these costs are amortised over a 45-year regulatory asset life (as per Ofgem's CEM framework), so the longer time period captures the total NPV of the costs, while the in-year or RIIO-ED2 time period captures only one or four years of the costs of this investment.