SP Energy Networks | DSO

DSO Performance Panel Submission 2025/26

SP Energy Networks | DSO

Contents

Glossary

Acronym	Name
ANM	Active Network Management
API	Application Programming Interface
CBA	Cost Benefit Analysis
CEM	Common Evaluation Methodology
CIM	Common Information Model
CMZ	Constraint Management Zone
COI	Conflict of Interest
CP2030	Clean Power 2030
CPA	Consistent Planning Assumptions
DBP	Data Best Practice
DER	Distributed Energy Resource
DESNZ	Department for Energy Security and Net Zero
DFES	Distribution Future Energy Scenarios
DMF	Decision Making Framework
DNOA	Distribution Network Options Assessment
ECR	Embedded Capacity Register
ED2	RIIO-ED2
ED3	RIIO-ED3
ENA	Energy Networks Association
ENZ	Engineering Net Zero
FSP	Flexibility Service Provider
GSPs	Grid Supply Points
I&C	Industrial and Commercial
ICCP	Inter-Control Centre Communication Protocol
INZAC	Independent Net Zero Advisory Council
LAEP	Local Authority Energy Plan

Acronym	Name
LANIT	Local Authority Network Insight Tool
LAs	Local Authorities
LCT	Low Carbon Technology
LHEES	Local Heat and Energy Efficiency Strategies
LMS	Load Management Schemes
LoMS	Local Management Scheme
LTDS	Long Term Development Statement
NAVI	Network Analysis and View
NDP	Network Development Plan
NESO	National Energy System Operator
NGED	National Grid Electricity Distribution
NGET	National Grid Electricity Transmission
NPg	Northern Powergrid
NPV	Net Present Value
NZIP	Net Zero Innovation Portfolio
ODP	Open Data Portal
PSR	Priority Service Register
RSP	Register of Strategic Projects
SP ENW	SP Electricity North West
SPD	SP Distribution
SPM	SP Manweb
SPT	SP Transmission
SROI	Social Return on Investment
SVF	Social Value Framework
tRESP	Transitional Regional Energy Strategic Plan
ToC	Theory of Change

Executive Introduction

We have made significant progress with our DSO development this year and led change across SP Energy Networks (SPEN). Through its leadership, our DSO is helping shift the business towards a more collaborative, whole-system, and future-focused operating culture, underpinned by clearer governance and more transparent management of strategic trade-offs. This includes notable developments such as delivering £14m of value in net direct benefits through our DSO activities, and unlocking RIIO-ED2 (ED2) benefits of £40m. We delivered our largest-ever increase in yearly flexibility and introduced a Demand Turn Up day-ahead flexibility product, which has improved our implementation of LV management, relieved transmission constraints, enabled social housing to take part in flexibility, and wider market development.

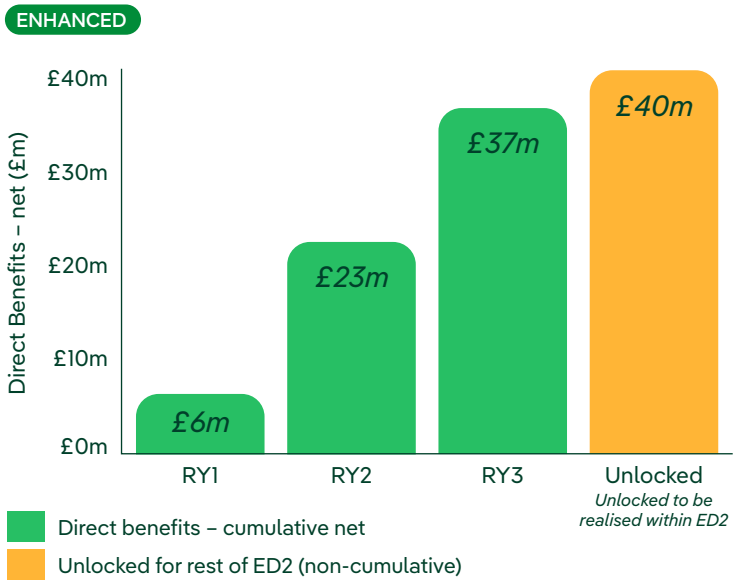
Nia Lowe, Head of DSO

1. Delivery of DSO Benefits

Our evolving DSO role places us as an enabler at the core of the energy system – facilitating the Net Zero transition not only through network investment and operational efficiency, but also the wider social impact our activities create. This year, we evolved the way we track and measure DSO benefits to reflect this role and capture the full impact of our actions. We built on our core methodology, developed by Frontier Economics, by adding the industry-standard methodology elements agreed through the ENA, and a new bespoke Social Value Framework (SVF) to develop the industry's first integrated approach to DSO benefit measurement. This captures the wider economic, environmental, financial, and public service value to society that our DSO activities enable (referred to as 'indirect' benefits), in addition to the benefits to bill payers and the environment that stem directly from our actions (referred to as 'direct' benefits).

This year, we delivered £14m in net direct benefits, bringing the cumulative ED2 total to £37m – and enabled a further cumulative ED2 total of £608m in indirect benefits. Our ability to understand the broader impact of our DSO activities is driving real changes in how we operate. For example, quantifying the benefits of flexibility for managing planned outages led us to scale up deployment of flexibility, directly reducing customer interruptions – this is discussed further in 1.2.4.

DSO Benefits Delivered (£m, 2020/21 prices)



The figure above presents the direct values and their growth over the ED2 period. A full breakdown of these figures can be found in the benefits results table in 1.1.1. All values reflect benefits to external stakeholders and exclude internal cost savings.

1.1 – Level of Ambition

Criteria	Key Evidence
1.1.1 – Evidence of the benefits of our DSO activities and how they correspond to our DSO strategy	New – Developed the industry's first integrated DSO benefits framework, combining (i) our independently developed core methodology, (ii) full adoption of industry-standardised elements across all outcomes, not only those in the ENA project, and (iii) a new SVF providing a single view of the direct and indirect benefits, including social, economic, environmental, and fiscal value of our DSO activities. We have delivered £219m of indirect benefits in 2025/26, with £608m delivered so far within ED2. Expanded – Delivered £14m of direct benefits in 2025/26 – bringing the ED2 cumulative total to £37m and unlocking an additional £40m for the rest of ED2, and indicating alignment with our DSO Strategy.
1.1.2 – Demonstrating how our DSO activities have impacted different types of consumers, network users, and the wider energy system	New – Benefit attribution now spans direct and indirect social benefits across five unique beneficiary groups – bill payers, Low Carbon Technology (LCT) customers, the wider economy, the environment and public services – with Theory of Change (ToC) models expanded to the beneficiary level for granular traceability from DSO activity to who benefits and by how much.
1.1.3 – Using a quantification of benefits that is consistent with established methods of economic appraisal	Expanded – Embedded the ENA standardisation guidance across the full benefit portfolio while continuing to ensure full alignment with established methodologies across all framework layers, including Green Book–style Cost Benefit Analysis (CBA) and Magenta Book theory and SROI-based valuation. Expanded – We have clearly articulated the key assumptions underpinning benefits quantification, and incorporated the assumptions underpinning our social value framework. These are available on our website.

1.1 – Level of Ambition *continued*

Criteria	Key Evidence
1.1.4 – Our work to promote wider system benefits	**Expanded –** Enabling greater DER access by expanding our Constraint Management Zones (CMZs) footprint from six to 19 zones, and deploying a new centralised ANM platform. Reduced transmission curtailment of 14 wind farms by absorbing excess generation through distribution Demand Turn Up flexibility. Working to improve T/D coordination through joint initiatives with NESO, including Demand Flexibility Services, megawatt (MW) Dispatch, the Local Constraint Market and Demand for Constraints.
1.1.5 – Taking a proactive role in regional cross-vector planning and interfacing with local actors	**Expanded –** We created two-way relationships in three areas – Local Authority (LA) and regional government engagement, whole-system investment planning with other networks, and collaboration with other sectors, including gas networks and industrial clusters– where local ambition now shapes our network planning and our network insight shapes local delivery. Full details and case studies are set out in 4.1.3.

1.1.1 – Evidence of the benefits of our DSO activities and how they correspond to our DSO strategy

Delivered £14m in direct and £219m in indirect DSO benefits in 2025/26 – bringing ED2 cumulative totals to £37m and £608m respectively, with a further £40m of direct benefits unlocked for the remainder of ED2. The table below presents the relationship between our DSO Strategy and its commitments, with our DSO activities, and the benefits these delivered as measured through detailed key performance indicators (KPIs). All direct benefits are reported as either already received by beneficiaries ('realised') or expected to be received before the end of ED2 from activities already delivered ('unlocked'), with no benefits reported as 'ambition', which are benefits that are forecasted on activities not yet delivered or implemented. Indirect benefits are reported as 'enabled', reflecting that the achievement of these wider outcomes depends on factors beyond our direct control. Please note that direct social benefits are reported as net, whilst indirect social benefits are reported as gross. We have retrospectively applied the new expanded framework across ED2, and thus recalculated the benefits for RY1 and RY2.

DSO Strategy commitments	DSO Activity	KPI for RY3 25/26	DSO Benefit	Beneficiary (£/#)	RY1 23/24	RY2 24/25	RY3 25/26	ED2 to date	Unlocked for ED2
Outcome 1: Deferring Reinforcement (see 1.2.1 for more detail)									
Investing in enhanced forecasting and flexibility Investing in infrastructure and processes for network planning	Contracting flexibility for reinforcement deferral	• Number of new sites with tendered flexibility: # 51 • Number of new sites with contracted flexibility: # 51 • Total peak flexibility tendered in any year across sites: 710 MW • Total peak flexibility contracted in any year across sites: 185 MW • Flexibility delivered within the year: 3,196 MWh • Gross deferred CAPEX: £7.3m	Reduced customer bills from avoided and deferred reinforcement costs	Bill payers (£ 000)	3,784	7,034	4,193	15,011	3,516
			Carbon savings through flexibility to defer reinforcement	Environment (£ 000)	37	31	18	86	1
			GVA supported through flexibility procurement expenditure	Wider economy (£ 000)	79	264	648	991	N/A
Investing £28.3m to deliver LV monitoring at 15,000 substations	Rolling out LV network monitors to identify spare capacity	• LV monitors installed (in-year): # 3,768 • LV monitors installed (cumulative): # 11,768 • Environmental sensors installed (cumulative): # 51	Reduced customer bills (via deferred reinforcement)	Bill payers (£ 000)	882	3,686	2,135	6,703	5,112
			Carbon savings from LV monitoring to defer reinforcement	Environment (£ 000)	26	84	36	146	103
			GVA supported through LV monitor installation and capacity enablement	Wider economy (£ 000)	74,617	292,129	204,182	570,928	N/A
Outcome 2: Outage Management & Optimisation (see 1.2.1 for more detail)									
Developing transparent and efficient dispatch framework Decision Making Framework covering coordination with NESO	Using flexibility to manage planned outages	• Sites identified for operational flexibility: # 4 • Sites with contracted operational flexibility: # 3 • Operational flexibility tendered: 53 MW • Operational flexibility contracted: 53 MW • Operational flexibility being dispatched within the year: 28 MWh	Benefits from managing planned outages	Bill payers (£ 000)	0	3,301	6,601	9,902	N/A
			Carbon benefits from managing planned outages**	Environment (£ 000)	0	20	40	60	N/A
			GVA supported through flexibility procurement expenditure	Wider economy (£ 000)	207	177	812	1,196	N/A

Key: Direct Social Benefits (Core) Indirect Social Benefits (Wider SVF). *All values in 2020/21 prices unless stated.*

**Aligned direct benefits are newly quantified benefits not yet in scope of ENA benefit-specific guidance, though the ENA's general appraisal parameters have been applied in full. Further information can be found in the following section.

1.1.1 – Evidence of the benefits of our DSO activities and how they correspond to our DSO strategy *continued*

DSO Strategy commitments	DSO Activity	KPI for RY3 25/26	DSO Benefit	Beneficiary (£/#)	RY1 23/24	RY2 24/25	RY3 25/26	ED2 to date	Unlocked for ED2
Outcome 2: Outage Management & Optimisation (see 1.2.1 for more detail)									
Developing transparent and efficient dispatch framework	Using flexibility for unplanned outages (Storms)	• Operational flexibility contracted for storms (StormFlex): 201 MW • Operational flexibility dispatched: 0 MWh	Benefits from managing unplanned outages	Bill payers (£ 000)	0	1,593	0	1,593	N/A
			Carbon benefits from managing unplanned outages**	Environment (£ 000)	0	7	0	7	N/A
Investing in LV monitoring Sharing near-time constraint warnings	Using LV monitoring to predict faults before they occur	• Potential faults identified: # 165 • Network controllable points installed: # 1,370	Avoided customer interruptions	Bill payers (£ 000)	26	93	127	246	255
Outcome 3: Accelerating DER Connections (see 1.2.1 for more detail)									
Giving users a common experience across GB Supporting shorter and longer contracts; building flexible connection routes	Offering accelerated connections (LMS, Technical Limits, Reformed Access Rights, Coordinated Solutions)	• Number of contracted customers via LMS/ Technical Limits (RY3): 4 (99 MW) • Number of contracted customers via Reformed Network Access Rights (RY3): 10 (260 MW) • Number of contracted customers via Coodinated Solutions: 2 (75 MW) • Number of contracted customers via other flexible connections (RY3): 7 (120 MW)	Reduced customer bills (via wholesale cost reduction)	Bill payers (£ 000)	0	0	5	5	6,633
			Operational carbon savings from earlier DER	Environment (£ 000)	0	0	9	9	24,197
Outcome 4: Strategic Optimisation & Regional Planning (see 1.2.1 for more detail)									
Using and developing enhanced forecasting tools Engaging with stakeholders annually on data needs	Strategic Optimisation Team (LCT optioneering & LA engagement)	• LAs engaged: 40 (100%) • LAs supported with optioneering: # 21 • EV sites optioneered: # 2,436 • Heat pump sites optioneered: # 134 • PV sites optioneered: # 9	Reduced cost due to resource savings**	Public sector (£ 000)	1,189	1,189	1,189	3,567	N/A
			Customer bill savings from accelerated EV charger, heat pump and PV deployment	LCT customers (£ 000)	2,161	2,610	3,239	8,010	N/A
			Carbon savings from accelerated EV charger, heat pump, and PV deployment	Environment (£ 000)	1,261	1,133	1,447	3,841	N/A
			Avoided NHS costs from mitigating excess cold hazards	Public sector (£ 000)	659	61	110	830	N/A
			GVA supported through LCT optioneering (EV chargers, Heat pumps and PV)	Wider economy (£ 000)	6,322	7,005	8,717	22,044	N/A

Key: Direct Social Benefits (Core) Indirect Social Benefits (Wider SVF). *All values in 2020/21 prices unless stated.*

**Aligned direct benefits are newly quantified benefits not yet in scope of ENA benefit-specific guidance, though the ENA's general appraisal parameters have been applied in full. Further information can be found in 1.1.1.

Evolving our benefits framework from robust foundations to an industry-first integrated methodology: Since the start of ED2, we have built the sector's most comprehensive DSO benefits methodology and we have extended it this year, operating as an integrated three-layer framework that is grounded in our ED2 DSO Strategy and its 77 commitments, a clear line of sight from strategic intent through to reported value. Each benefit is linked to a DSO activity, supporting KPIs, and a named ToC. The result of a multi-year programme, the framework combines a rigorous independent foundation with industry standardisation to form an integrated framework for the measurement of direct and indirect benefits. We learn and shape our actions and investment according to the insight generated by this framework – examples are provided in 1.1.4 and 1.1.5.

1.1.1 – Evidence of the benefits of our DSO activities and how they correspond to our DSO strategy *continued*

Layer 1: An independently developed, Green Book-aligned core methodology

- Our benefits framework was developed independently by Frontier Economics in close partnership with our DSO experts.
- Designed to align with established economic appraisal methods and with HM Treasury Green Book (2022) and Magenta Book (2020) principles (see 1.1.3 on how this alignment is embedded across every layer of the framework), this independent framework remains transparent and rigorous through the direct involvement of our DSO team in specifying assumptions and validating outputs, providing a robust foundation for further development.

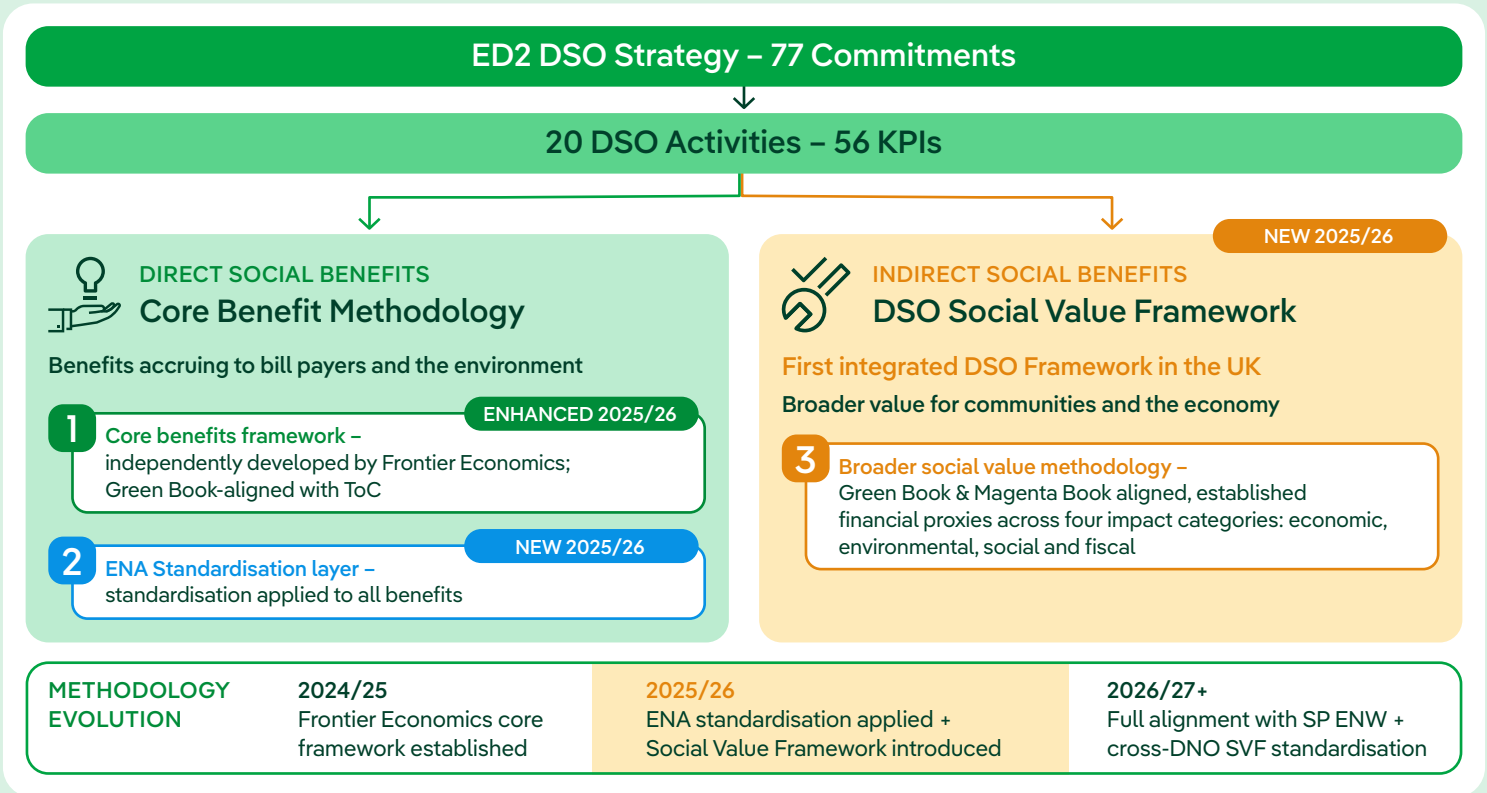
Layer 2: ENA standardisation – driving comparability across networks

- This year, we incorporated outputs from the ENA DSO Benefits Methodology project – a cross-DSO initiative responding directly to Panel feedback on improving consistency in benefit quantification and reporting.
- The ENA project standardised 13 methodology elements across nine benefits in three outcome areas – Accelerating DER Connections, Deferring Reinforcement, and Outage Management and Optimisation – covering general appraisal parameters (e.g. price base and net reporting) and benefit-specific requirements (e.g. ToC structure and benefit duration). All in-scope direct benefits are fully aligned with all 13 methodology elements, and previously stated figures have been recalculated retrospectively to ensure consistent tracking from RY1 onward. We have expanded our application of the ENA standardisation beyond the project's three outcome areas to our full benefits portfolio.
- Beyond the ENA work, we are working closely with SP Electricity North West (SP ENW) to identify differences in non-standardised methodologies and develop a joint roadmap to address them in the coming weeks. This will position SPEN and SP ENW as the first DSOs to achieve full methodological alignment on DSO benefits, establishing a new benchmark for cross-network consistency. We see this as a valuable extension of the work initiated by the ENA Benefits Standardisation Group. On completion, we will share our learnings with the wider industry to help drive further standardisation.

Layer 3: The DSO Social Value Framework – creating the industry's first integrated approach to indirect social benefits

- The most significant enhancement to our methodology this year is the introduction of our DSO SVF, developed by Sirio Strategies in close collaboration with our DSO team, making us the first UK DSO to integrate and quantify both direct and indirect social benefits within a single framework.
- The SVF systematically captures indirect social benefits, applying Social Return on Investment (SROI) principles consistent with Green Book and Magenta Book guidance. It maps indirect benefits across four impact categories: economic (such as Gross Value Added (GVA) linked to flexibility procurement and LCT investment); environmental (such as monetised carbon avoided through accelerated electrification); social (such as customer bill savings from earlier LCT deployment); and fiscal (e.g. avoided NHS costs from heat pump deployment in fuel-poor households). Crucially, each indirect benefit is linked to a specific DSO activity and the same KPIs that drive core benefit measurement, ensuring the two layers are fully integrated.
- All benefits presented within the SVF are expressed in gross terms, rather than net, as they reflect the total system-wide value linked to DSO activities without isolating the share directly attributable to our contribution. These benefits are also presented as enabled, rather than realised, because the delivery of final outcomes depends on multiple steps outside our direct control.
- We recognise this is a new area of measurement and that refinement will continue. We are already aligning our SVF approach with SP ENW and intend to work through the ENA DSO Collaboration Group to explore broader standardisation of indirect social benefit measurement across all DSOs.

This integrated framework extends our view of value beyond the distribution system to broader societal and economic impacts, strengthening accountability as stakeholders have visibility of the core network value we deliver alongside the wider economic and social value our activities enable. It also shapes decisions – where attribution evidence shows an activity delivers disproportionate wider value (e.g. strategic optimisation that accelerates LCT deployment in fuel-poor areas), that evidence feeds directly into delivery choices and relocation. As we scale DSO activity through ED2 and into ED3, this integrated view will be central to directing effort where it creates the greatest overall value for customers and society.



1.1.2 – Demonstrating how our DSO activities have impacted different types of consumers, network users, and the wider energy system

Introducing beneficiary attribution: Our integrated methodology, set out in 1.1.1, enables us to attribute benefits across the full scope of DSO value – both the direct social benefits quantified through the core benefits framework and the indirect social benefits captured through the SVF. This means we can now report not only what value the DSO activities create, but who receives that value and through which mechanism. We are beginning to frame our benefits activity within a wider Social DSO strategy, reflecting the broader role our DSO activities play in supporting customers and society. As part of our future integration with SP ENW, our SVF and move to a Social DSO Strategy is an early step in this shift, helping us evidence wider social value beyond direct network and bill impacts.

To achieve this, we expanded our ToC models from the benefit level – as set out in the 2024/25 Frontier core framework – to the beneficiary level. Each ToC now links a specific DSO activity to its outputs, outcomes, benefits, and the groups that receive them. For example, Network Flexibility and Constraint Management deliver avoided reinforcement costs for bill payers, while the same activity also generates wider economic value and carbon reduction through the SVF. This clearer linkage between activity, benefit, and beneficiary supports more transparent reporting and targeted decision-making.

The table below presents the cumulative benefits attributed to each beneficiary group across ED2, distinguishing between realised benefits (RY1–RY3) and benefits unlocked for the remainder of the price control period.

Beneficiary	RY1 23/24	RY2 24/25	RY3 25/26	ED2 to date	Unlocked for ED2
Direct Social Benefits (Benefits are presented in net terms)					
Bill payers – Reduced bills via deferred reinforcement, wholesale cost savings	£4.69m	£15.71m	£13.06m	£33.46m	£15.52m
Environment – Reduction in carbon emissions through deferring reinforcement and flexibility	£0.06m	£0.14m	£0.10m	£0.30m	£24.30m
Public sector – Reduced cost due to resource savings	£1.19m	£1.19m	£1.19m	£3.57m	N/A
Indirect Social Benefits Enabled (Benefits are presented in gross terms)					
Wider economy – GVA from LCT investment and flexibility procurement	£81.23m	£299.57m	£214.36m	£595.16m	N/A
LCT customers – Earlier bill savings from accelerated EV charger, heat pump, and PV deployment	£2.16m	£2.61m	£3.24m	£8.01m	N/A
Environment – Monetised earlier carbon reduction from accelerated EV charger, heat pump, and PV deployment	£1.26m	£1.13m	£1.45m	£3.84m	N/A
Public sector – Avoided healthcare costs from mitigating excess cold hazards via heat pump deployment	£0.66m	£0.06m	£0.11m	£0.83m	N/A

1.1.3 – Using quantification of benefits that is consistent with established methods of economic appraisal

Ensuring continued full alignment with established methodologies: Our integrated methodology meets this standard across its full scope of direct and indirect social benefits through three reinforcing layers of assurance:

- The core benefits framework, independently developed by Frontier Economics, was built around a Green Book–style social cost–benefit analysis. Each DSO activity is assessed against a business-as-usual (BAU) counterfactual, with benefits and costs discounted at the standard 3.5% social discount rate and reported as a Net Present Social Value. The methodology follows the Magenta Book's recommended ToC approach. Monetisation draws on established valuation sources (e.g. DESNZ carbon appraisal values).
- The ENA standardisation layer, adopted this year, codified 13 methodology elements into a consistent cross-DSO standard developed collaboratively across all six DSO groups. This governs foundational appraisal choices – counterfactual definition, price base, carbon valuation, net benefit reporting, and double-counting rules – each grounded in specific Green Book provisions. Our initial framework was already aligned with these principles and is now updated to reflect the appraisal choices of the ENA Standardisation. This layer converts that alignment from a design choice into a governed, auditable standard applied across the full benefit portfolio. Furthermore, to ensure that all our reported benefits are robust and grounded in delivered activity, we report only realised and unlocked benefit: value that will be received based on activities already delivered. We do not quantify ambition benefits that are contingent on future actions not yet taken.
- The SVF applies the same appraisal rigour to indirect social benefits, quantifying them as the incremental impact of DSO activities relative to a do-nothing baseline and monetising them using established public-sector valuation sources (e.g. Scottish Government Input–Output Tables for GVA, DESNZ-published carbon values, and BRE's Cost of Poor Housing evidence base for avoided NHS costs). This approach follows Magenta Book evaluation principles, with a transparent logic chain from DSO activity to monetised benefit, and assumptions individually documented, sourced, and stated in an explicit price base. Double counting between direct and indirect benefits is avoided by mapping benefits to distinct beneficiary groups through the ToC, with indirect benefits defined to exclude any value already captured in the core framework. Where pertinent, benefit definitions and valuations are consistent with DSO Rulebook benefits, ensuring cross-sector comparability.

The methodology published on our website maps established appraisal principles to our core benefits framework and our SVF.

1.1.4 – Our work to promote wider system benefits

Facilitating greater DER access: We are accelerating Distributed Energy Resource (DER) connections via Technical Limits, Reformed Network Access Rights, and Coordinated Solutions for demand, generation, and storage ahead of reinforcement in transmission-constrained areas. This year, we contracted connections for 16 DER, 14 in SP Distribution (SPD) (333 MW) and 2 in SP Manweb (SPM) (101 MW), totalling 434 MW. As explored in 5.1.3, we expanded newer active network management (ANM)- type CMZs, from six to 19, enabling connections ahead of distribution and transmission reinforcement. This enabled contracted connections for three DER (72 MW) in SPD and four (48 MW) in SPM this year. Together, these approaches increase network access and reduce constraint-driven curtailment for DER, and have delivered over £6.64m in ED2 benefits under Outcome 3, enabling 1.53 GW of DER to connect in transmission-constrained areas since we began offering flexible connections.

Using Demand Turn Up to Reduce Transmission Curtailment: We used distribution-level Demand Turn Up as a whole-system tool to support transmission constraints in areas with high volumes of wind generation. With our control room, we identified three Grid Supply Points (GSPs) with 14 connected wind farms, which would need to be curtailed during high-wind periods due to transmission constraints. We delivered around 100MWh of additional demand turn-up over two months, helping absorb generation locally, relieve transmission constraints, and reduce the need for NESO to curtail renewable output. These wider whole-system benefits are not yet captured in the current benefits model, and we will, in the future, update our framework to include these.

Improved coordination across the T/D boundary: We are progressing several joint initiatives with NESO that will enable distribution-connected DER to participate more efficiently in NESO's markets.

- Demand Flexibility Services: working with NESO to allow distribution-connected domestic customers to participate in transmission demand turn-up markets.
- Megawatt Dispatch: working to enable our 5,707 MW of distribution-connected DER to participate in NESO markets, reducing the risk of conflicting dispatch signals and utilised efficiently by whichever part of the system needs them most.
- Local Constraint Markets: working to relieve transmission constraints with distribution demand turn-down flexibility, improving whole-system efficiency, and reducing costly transmission-level interventions.
- Demand for Constraints: working with NESO to develop access to distribution-connected flexible demand markets, using discounted tariff rates to offset excess renewable generation and avoid paying for generation curtailment.

1.1.5 – Taking a proactive role in regional cross-vector planning and interfacing with local actors

We take a proactive role in regional cross-vector planning, which forms part of our DSO Strategy Commitments and activities under Outcome 4: Strategic Optimisation and Regional Planning. Full details on this can be found in 4.1.3, but at a high level this spans three main areas:

- LA and Regional government engagement: we engage and support 12 regional bodies' decarbonisation plans, and conduct quarterly engagement with 40 LAs, supporting Local Heat and Energy Efficiency Strategies (LHEES) and Local Area Energy Plans (LAEPs) inputs, and providing optioneering support through our award-winning LANIT tool for 2,579 LCT locations.
- Whole-system investment planning: working with NGET on the Mersey Ring Upgrade to support North-South transmission capacity. In Mid Wales, we are working with NGET, NGED, NESO, IDNOs, DESNZ, and the Welsh Government to assess coordinated transmission and distribution solutions, delivering a whole-system investment recommendation for the region. Finally, we are working with SP Transmission (SPT) to address cross T/D boundary needs identified by our Distribution Future Energy Scenarios (DFES) and the transitional Regional Energy Strategic Plan (tRESP).
- Collaborating with other sectors: we work with network users, including gas networks, three industrial clusters, three investment zones, and three transport bodies, to understand their needs and ensure our planning supports their future developments.

This RY3, we strengthened cross-sector engagement through over 100 tRESP meetings with NESO and stakeholders. tRESP outputs are now within 1% of our DFES and LCT forecasts, including our Clean Power (CP) 2030 Gate 2 outlook. This level of alignment is not seen in all DSOs and reflects the strength of our forecasting and our close collaboration with NESO, including detailed geospatial review of the pathways and planning assumptions with testing, review, and feedback throughout tRESP development. These shared pathways now inform our ED3 load plan, with further detail in 4.1.3.

1.2 – Benefits Realisation

Criteria	Key Evidence
1.2.1 – Articulating the benefits realised during the RIIO-ED2 period through the delivery of our DSO strategy	**Expanded –** Core benefits are quantified using the ENA Benefits Framework, while wider system and societal benefits (e.g. carbon emission savings and economic impacts) are captured via our SVF. **Expanded –** Demonstrated and evidenced how benefits are realised, with clear links between DSO Strategy, activities, and benefits across outcomes areas with full pathways from ToC models and case studies.
1.2.2 – Developing robust processes and KPIs for tracking benefits	**New –** Fully embedded, three-phase, KPI tracking process integrated into the benefit measurement process via ToC models. **New –** Dedicated DSO resource now runs KPI collection and validation, enabling quarterly in-year tracking rather than year-end reporting. **New –** Structured dashboard gives the whole business live visibility of core DSO KPIs, replacing siloed year-end reporting. **Expanded –** Streamlined flow from validated KPIs into the benefit models delivers a live view of DSO benefits, informing in-year decisions on where to scale, redirect, or course-correct.

1.2 – Benefits Realisation *continued*

Criteria	Key Evidence
1.2.3 – Adapting our plans where opportunities to increase benefits were identified	New – Launched Demand Turn Up day ahead markets, and enabled five social housing estates to participate in flexibility, with additional households being added in the Summer. Expanded – Recognised benefits driven by flexibility for planned outages, and changed our approach to flexibility stakeholder engagement and market development to drive our largest ever growth in flexibility availability.
1.2.4 – Delivering additional outputs to maximise benefits for customers	Expanded – Recognised the significant positive impact StormFlex had on unplanned outages for customers last year, and expanded its development this year, going from one provider with 20 MW to four with 201 MW.

1.2.1 – Articulating the benefits realised during the RIIO-ED2 period through the delivery of our DSO strategy

Our quantification follows a clear Theory of Change: ED2 strategy commitments translate into DSO activities, each tracked through KPIs, which generate outcomes and resulting benefits that can be quantified using our leading integrated methodology, discussed in 1.1.1.

In this section, we group benefits by the core outcomes delivered by our DSO activities. This structure aligns our reporting with the common framework adopted by all network companies under the ENA standardisation effort, enabling benefit comparison where methodologies are standardised. Benefits reported under 'Deferring reinforcement', 'Outage Management and Optimisation', and 'Accelerating DER connections' are fully aligned with the ENA standardised methodology elements and are more closely comparable across DSOs. Benefits reported under other outcomes (e.g. Strategic Optimisation) apply the same methodology elements where possible but are not yet fully standardised across the sector, and are clearly distinguished.

All activities discussed 1.2.1 are connected to our ED2 DSO strategy commitments

Theory of Change: Outcome 1 – Deferring Reinforcement

DSO commitment	Activity	Outputs/KPI	Benefit	Beneficiaries
Investing in enhanced forecasting and flexibility Investing in infrastructure and processes for network planning	Contracting flexibility for reinforcement deferral	• New sites successfully contracted • Total peak flexibility tendered • Total peak flexibility contracted • Flexibility delivered within the year	Reduced customer bills from deferred reinforcement through flexibility and LV monitoring	Bill payers
			Carbon savings from deferred reinforcement through flexibility and LV monitoring	Environment
Investing [£28.3m] to deliver LV monitoring at [14,102] substations	Rolling out LV network monitors to identify spare capacity	• LV monitors installed • Cumulative LV monitors installed • Cumulative Environmental sensors installed	GVA supported through LV monitor installation and capacity enablement	Wider economy

Direct Benefits | Indirect Benefits

Contracting flexibility for reinforcement deferral

Direct benefits realised in-year: Domestic customers benefited from lower bills from avoided or deferred reinforcement costs, valued at £4.19m with carbon savings of £18k in RY3.

Indirect benefits realised in-year: Flexibility Service Providers (FSPs) benefited from contract revenues, while wider social benefits were captured in the SVF as a GVA of £0.65m in RY3.

How we delivered the benefits: Building on the market development work as set out in Section 3, we have continued to deploy flexibility to defer reinforcement and reduce customer bills. Improvements to procurement, market design, and provider engagement increased participation and delivery, enabling flexibility to be used more often and more effectively as an alternative to reinforcement at constrained sites. In RY3, flexibility was contracted at 51 sites (27 in SPD and 24 in SPM), with 710 MW peak flexibility tendered (274 MW SPD and 436 MW in SPD), 185 MW (32 MW in SPD and 153 MW in SPM) contracted, and 3,196 MWh (1,030 MWh in SPD and 2,166 MWh in SPM) delivered, deferring or avoiding reinforcement, and identifying £7.30m of deferred CAPEX across relevant sites. We have significantly grown available flexibility levels through various initiatives to improve market access, including Demand Turn Up Day-Ahead markets and expanded tailored support for FSPs, as set out in 3.2.2.

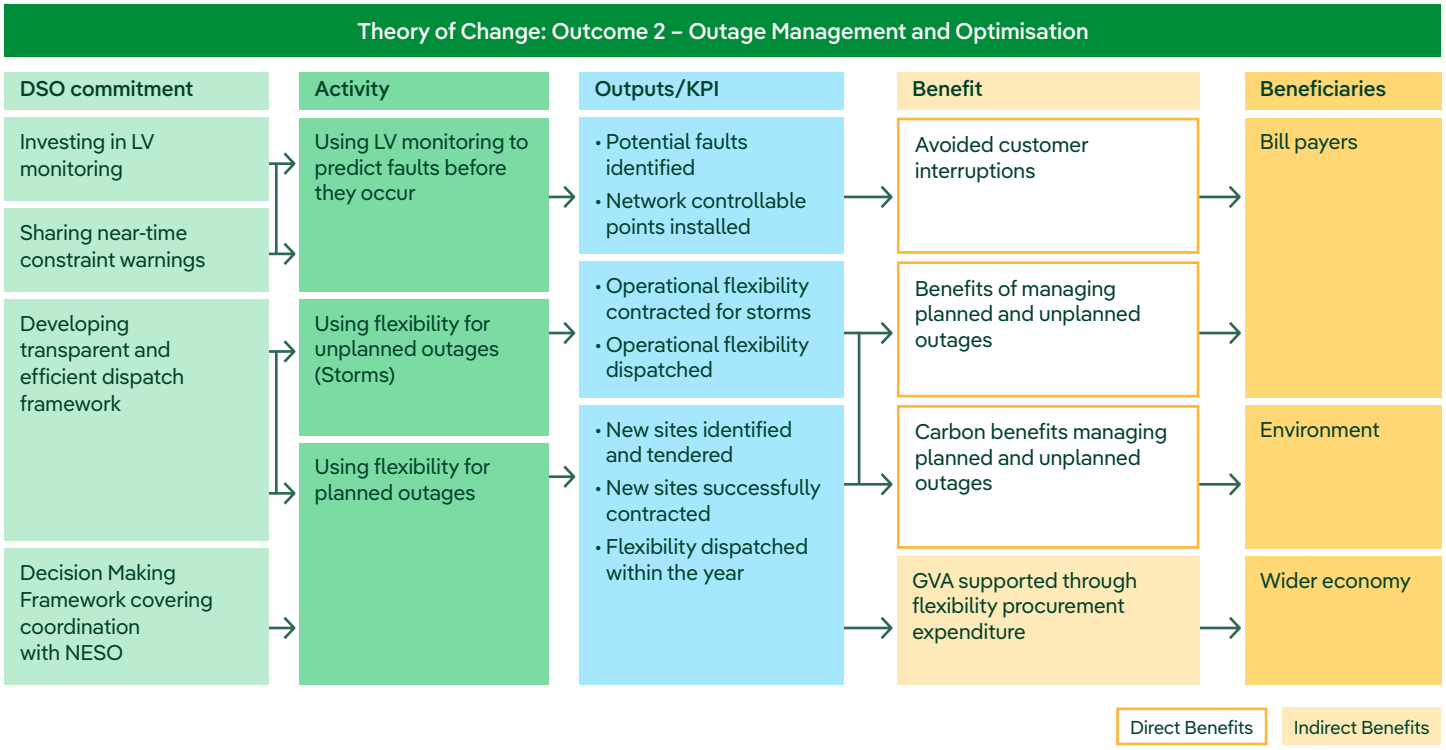
1.2.1 – Articulating the benefits realised during the RIIO-ED2 period through the delivery of our DSO strategy *continued*

LV monitoring to defer reinforcement

Direct benefits realised in-year: Bill payers benefited from lower bills from deferred network reinforcement due to improved network headroom calculations, valued at £2.14m in RY3, with carbon savings of £36k in RY3.

Indirect benefits realised in-year: Where unlocked LV capacity is fully utilised by new domestic LCT connections, the SVF indicates a potential £204.18m of GVA in RY3. This estimate draws on three robust data sources: i) our network planning data to quantify the capacity unlocked, ii) our strategic optioneering activity to determine the expected LCT installation mix within the license area, and iii) Fraser of Allander Institute research to translate LCT deployment into broader economic value using standard Input-Output methodology.

How we delivered the benefits: The benefit in RY3 reflects the continued rollout and use of LV monitoring, with an expanding installed base identifying additional spare capacity across the network and enabling further reinforcement deferral as a result. This marked a shift from investing in monitoring infrastructure only for fault detection to using monitoring data more actively to assess where reinforcement could be deferred, and where flexibility or operational solutions could be used instead. In RY3, we installed 2,205 LV monitors in SPD and 1,563 in SPM for a total of 3,768 LV monitors, taking the total to 11,768, and increased use of monitoring data to assess headroom and inform planning and connection decisions. As set out in 2.1.2 and 5.1.1, additional monitoring and better use of real-time data improved our ability to identify LV network capacity and target interventions more effectively.



Flexibility for planned outages

Direct benefits realised in-year: Domestic and business customers benefited from fewer and shorter interruptions where flexibility was used to maintain supply during planned works, delivering £6.60m in RY3. Vulnerable and Priority Service Register (PSR) customers benefited particularly through improved continuity of supply, and similarly DER providers benefited from allowing generation to continue operating, increasing revenues. This created broader, unquantifiable benefits by reducing curtailment of low-carbon generation, including bill savings and carbon savings for wider society.

Indirect benefits realised in-year: FSPs benefited from contract revenues, while wider social benefits were captured in the SVF as £0.81m in RY3 of GVA supported through flexibility procurement expenditure, reflecting the 4.5-fold increase in MW contracted year-on-year.

How we delivered the benefits: The increase in benefit in RY3 reflects a significant scale-up in the use of flexibility to support planned activities. Building on the wider ramp-up described in Section 3, we used flexibility more systematically to maintain supply during planned works, reducing customer interruptions and avoiding more disruptive or higher-cost alternatives. In practice, three sites were identified and contracted, with 53 MW tendered and contracted, and 28 MWh delivered in-year. This allowed us to manage outage risk through flexibility, reflecting that not all contracted flexibility was delivered. As such, in several cases, customers remained on supply during planned outages, and DER generation continued.

Using flexibility for unplanned outages

Direct benefits realised in-year: In RY3, our network demonstrated sufficient resilience that no flexibility dispatch was required for unplanned outages, and no benefit is therefore reported (0 MWh dispatched). This means the underlying value of how we manage unplanned outage risk is not yet captured; thus, we are developing a methodology to value this risk. Where deployed, this service benefits domestic and business customers through faster restoration and shorter interruptions, with particularly strong benefits for vulnerable and PSR customers through improved continuity of supply.

How we delivered the benefits: We increased contracted StormFlex, our industry-leading flexibility product for managing outages during severe weather events, capacity from 20 MW to 201 MW to further strengthen our ability to respond to severe weather events , although this year we did not experience any named storms severe enough to need StormFlex , as explored further in 3.1.2. The additional capacity has improved our operational readiness to support restoration and reduce interruption durations when unplanned outages occur.

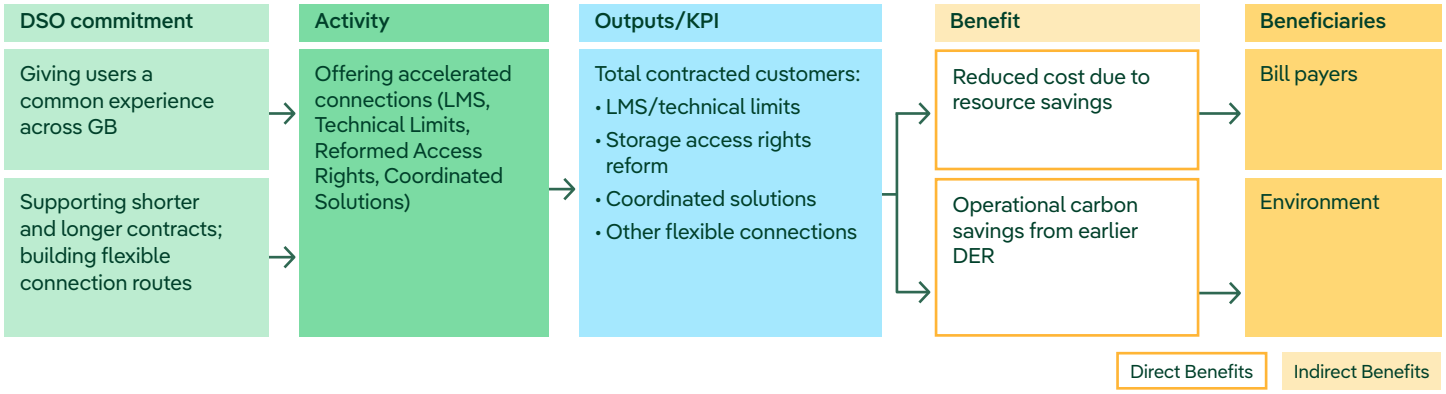
1.2.1 – Articulating the benefits realised during the RIIO-ED2 period through the delivery of our DSO strategy *continued*

Using LV monitoring to predict faults

Direct benefits realised in-year: Domestic and business customers received £0.13m in benefits from fewer faults escalating into interruptions, with 165 potential faults identified. Vulnerable and PSR customers benefited in particular from improved continuity of supply, though this is not separately monetised.

How we delivered the benefits: The contribution of LV monitoring to this outcome increased in RY3 as improved visibility enabled earlier identification of and intervention around emerging faults. This reflects increasing use of monitoring and platform data to move from reactive fault response towards earlier detection and targeted repair.

Theory of Change: Outcome 3 – Accelerating DER Connections

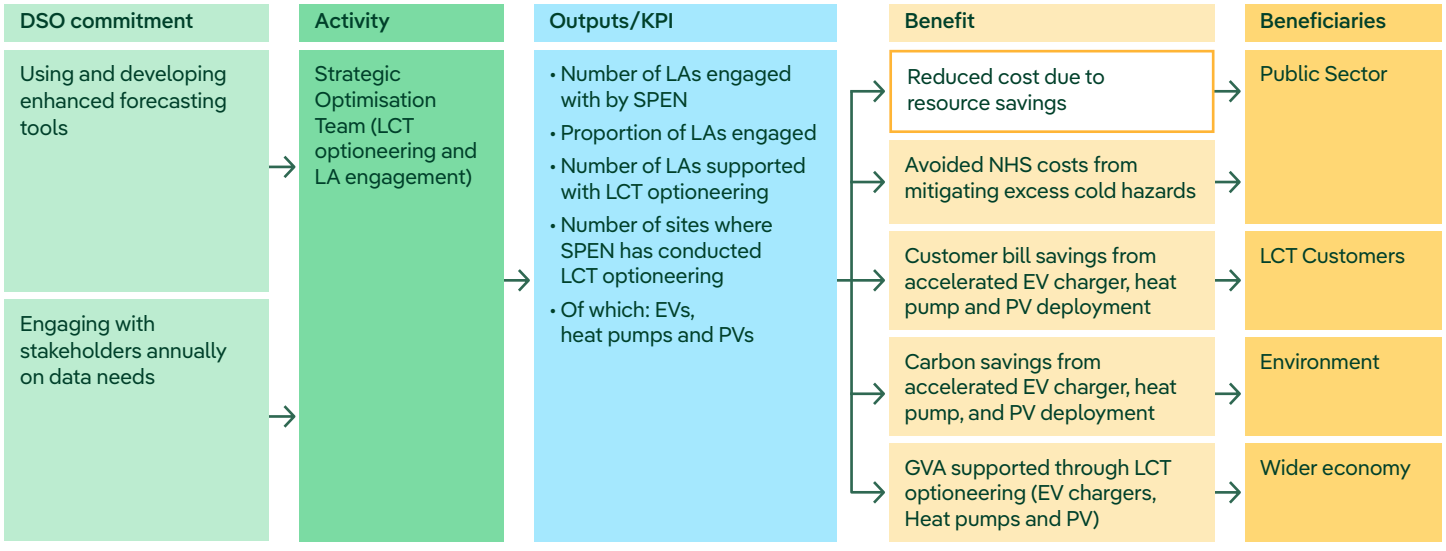


Accelerating DER connections

Direct benefits realised in-year: In RY3, a total of £14k of direct benefit was realised with the full value of this activity will be felt in future years as accelerated connections come online. By the end of ED2, we expect this to translate into £6.63m in customer bill savings and £24.20m carbon savings, with customers benefitting from earlier access to network capacity, accelerating the deployment of generation, storage, and low-carbon demand technologies. Further information can be Section 5.

How we delivered the benefits: We continue to expand flexible connection solutions, including Technical Limits, Reformed Network Access Rights, and coordinated approaches. Explored in 5.13, this shift towards flexibility and alternative connection arrangements helps unlock capacity and reduce delays. 23 customers (17 in SPD and six in SPM) were contracted to connect, enabling 554MW of capacity (405 MW in SPD and 149 MW in SPM). This gave generation, storage, and low-carbon demand customers earlier network access that might otherwise have been delayed by reinforcement.

Theory of Change: Outcome 4 – Strategic Optimisation and Regional Planning



Strategic Optimisation Team

Direct benefits realised in-year: LAs were the main beneficiaries, gaining improved planning capability and better-informed investment decisions to support decarbonisation plans, with £1.19m of in-year core benefit delivered in RY3.

Indirect benefits realised in-year: More efficient electrification and improved planning generated wider societal value, including £8.72m of GVA, £1.45m of avoided emissions, and £0.11m of avoided NHS costs in RY3. More broadly, this activity supported improved access to LCTs, including for vulnerable households, although that benefit is not separately monetised.

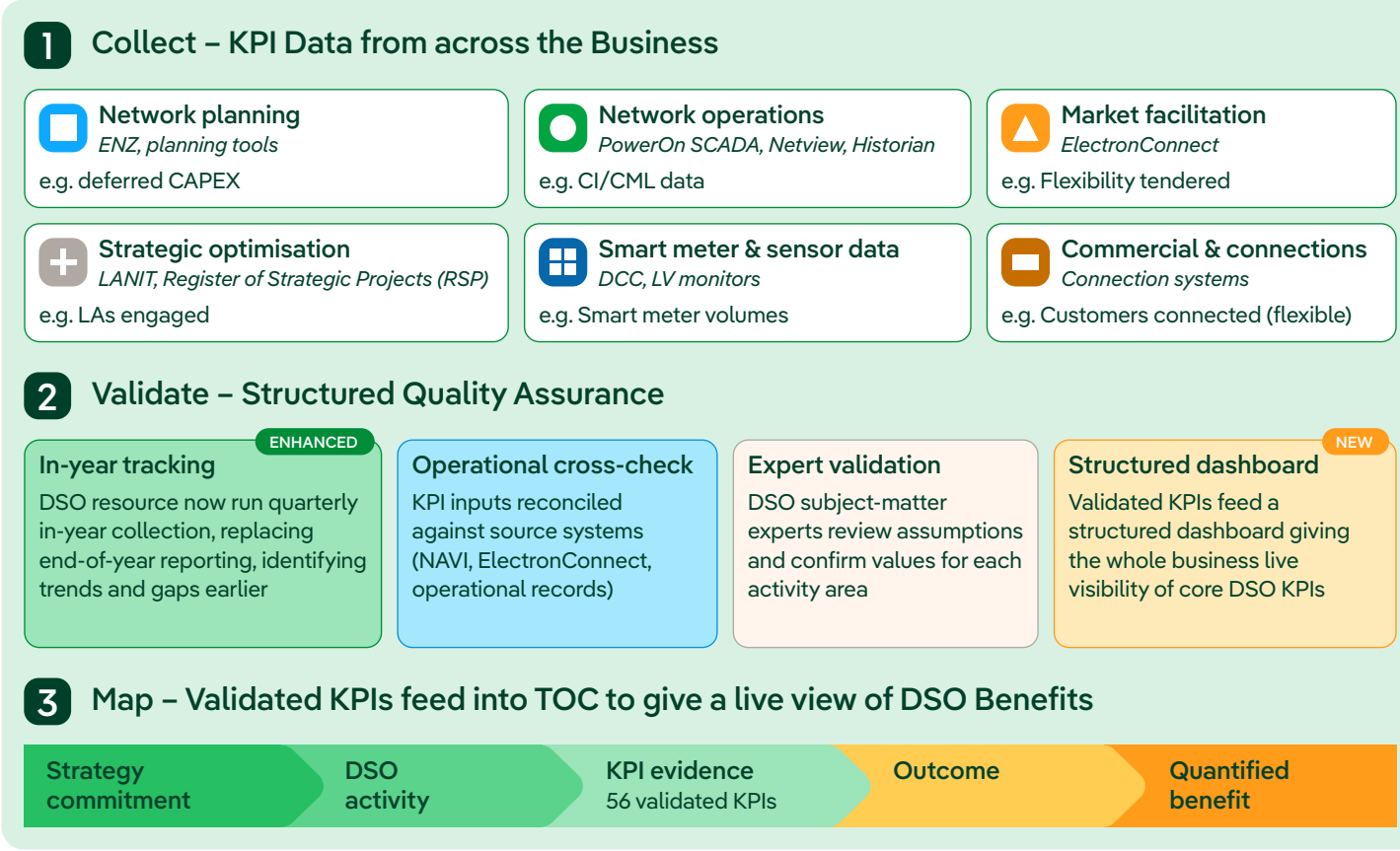
How we delivered the benefits: In RY3, we have continued to engage with all 40 LAs in our license areas. LANIT has enabled us to expand our support significantly, with 21 LAs supported with detailed optioneering and analysis delivered across 2,436 EV sites, 134 heat pump sites, and nine solar PV sites – giving stakeholders clearer, evidence-based pathways for decarbonisation and helping bring forward viable projects. This is further described in 4.1.3.

1.2.2 – Developing robust processes and KPIs for tracking benefits

The diagram below presents our robust process for tracking KPIs and DSO benefits. KPIs are collected from six operational areas, drawing on source systems including the Engineering Net Zero (ENZ) platform, PowerOn SCADA, Netview, Historian, ElectronConnect, and LANIT – described further in the following chapters – then validated through structured expert review and reconciled against operational records. For the first time this year, a dedicated DSO resource manages this process, moving us from end-of-year reporting to more frequent KPI data collection – from real-time monitoring (e.g. registrations on the Open Data Portal (ODP), portal feature-page access) through to quarterly tracking.

Validated KPIs feed into a new dashboard that gives the business live visibility of core DSO KPIs, replacing siloed year-end reporting with continuous oversight across planning, operations, market facilitation, strategic optimisation, and connections teams.

These KPIs then flow directly into the ToC for each DSO activity. We have streamlined this link to the benefit models to provide a live view of DSO benefits, helping us decide in-year where to scale, redirect or course-correct, rather than relying only on year-end reporting. Evidence of benefits-driven decision-making is evidenced in 1.2.3 and 1.2.4.



1.2.3 – Adapting our plans where opportunities to increase benefits were identified

After seeing the value flexibility delivered to customers in reducing time off supply during planned and unplanned outages, we revised our market development approach to accelerate participation and amplify those benefits, as explored in 3.1.3, enabling us to double the direct benefits from planned outage flexibility from £3.3m to £6.6m. We replaced a generic engagement model with a tailored support scheme based on six FSP personas and targeted our one-to-one engagement KPI, increasing one-to-one support from 109 meetings last year to over 300 this year, and published persona-specific support materials. Combined with other market support measures, this increased registered providers from nine to 37 and registered assets from 33,394 to 110,894.

In addition, we identified social housing households as a group that could benefit from flexibility but face barriers to participation. We therefore adapted our approach to enable them to take part in Demand Turn Up and Demand Turn Down tenders, working with social housing managers, tariff providers, and Connected Response, which retrofits electric storage heaters with smart controls, and are implementing across five housing estates in Scotland. This creates income to help reduce heating costs and fuel poverty, while also supporting energy efficiency and new LV flexibility opportunities, as explored in 3.1.4.

1.2.4 – Delivering additional outputs to maximise benefits for customers

Last year, we saw significant benefits from StormFlex, where for every MWh dispatched during an unplanned storm outage, customers realised £39k in benefits from being brought back on supply faster, and the wider environment avoided 0.65tCO2e of carbon emissions by avoiding carbon-intensive backup generation. As such, this year we accelerated its development to maximise the value it can deliver to customers during future storm events. We expanded provider participation, growing StormFlex from one provider with 20 MW to four providers delivering 201 MW, and diversified the asset types so we are not reliant only on hydroelectric generation. No named storms this year required StormFlex to be dispatched; however, during Storm Amy, StormFlex could have brought 250,000 customers back on supply, compared with only 15,000 customers restored during Storm Darragh last year. As a result, no direct benefits accrued this year, which highlights a limitation in the current methodology, which captures value when flexibility is used but does not fully reflect the risk reduction and resilience benefits of having StormFlex available.

2. Data and Information Provision

This year, we addressed the Panel's feedback on data accessibility, critical datasets, and the need for clearer evidence of stakeholder-led provision by putting stakeholders at the centre of our delivery and strengthening the ODP as the main access point for our data, tools, and supporting information. We used feedback from our Open Data Survey, events, the DSO Performance Panel, bilateral discussions, and more than 300 data requests to identify the main barriers stakeholders faced in finding, understanding, and applying our data. We then prioritised delivery around the datasets, tools, and guidance that would most improve stakeholders' ability to assess capacity, plan projects, and use our data in their own workflows.

This led us to publish 18 new datasets, including five which were the most requested by stakeholders, alongside new feature pages, dashboards, and catalogues that make high-value data easier to find and use. Key additions included a new ODP filter for short- and long-term constraint forecasts, improved DER visibility, and clearer access to hosting capacity and network options data. Together, these changes improved visibility of network performance, emerging constraints, and connection opportunities, supporting place-based planning, flexibility participation, and operational decision-making.

We also improved usability, transparency, and confidence in the data itself. We refreshed the ODP homepage, added the Recite Me accessibility tool, expanded how-to resources and Application Programming Interface (API) guidance, published clearer metadata and became the first DSO to publish Data Quality Assessments for our ODP datasets. Together, these changes make our data easier to find, understand, and use with confidence.

2.1 – Scope, granularity, and accuracy of data

Criteria	Key Evidence
2.1.1 – Sharing comprehensive planning, market, and operational data, and additional data for stakeholder value	**Expanded –** Continued publication of all DSO Baseline Expectation datasets, and expanded our open data offer with 18 new datasets in 2025/26, including the following highlights: • Improved DER visibility: our Embedded Capacity Register (ECR) completeness increased from 85% in 2025 to 99.99% in 2026, and validity improved from 85% to 86.5%, while maintaining overall quality (92.3% to 92.7%) • Expanded constraint visibility by bundling constraint datasets into a single theme on the ODP for short- and long-term constraints forecasts • In response to Panel feedback, grouped constraint and hosting capacity datasets into dedicated ODP catalogues, making relevant data easier to find and use • Including five new datasets added in response to stakeholder requests, supported by four new feature pages and dashboards to improve usability **Expanded –** Addressed 300+ Open Data Requests to provide additional data to stakeholders. **Existing –** Refreshed our stakeholder-informed Data Roadmap using evidence from our Open Data Survey, webinars, DSO events, and direct feedback, creating a clear link between stakeholder priorities and the datasets and tools we prioritised.
2.1.2 – Considering and using third-party data, including smart meter data	**Expanded –** Increased the use of smart meter data in our network digital twin, NAVI, enabling a range of capabilities from detecting unregistered EVs to identifying technical losses. We also now publish smart meter penetration data on the ODP, including as an interactive map. **Existing –** Improved our integration of third-party data through: • RSP capturing regional and local government heat, transport, and industrial projects to inform our DFES • DFES integrates additional third-party data, such as tRESP, weather, census, and postcode-based data, strengthening forecast accuracy and aligning network planning with local developments.
2.1.3 – Sharing underlying methodologies and other insights	**New –** Added four new feature pages and dashboards sharing insights based on stakeholder requests.
2.1.4 – Approach to improving data quality and the processes in place to address gaps in datasets and improve standards, ensuring accurate and unbiased data	**New –** Enhanced and aligned dataset descriptions across the ODP, helping stakeholders understand coverage and limitations more quickly and combine datasets more easily in their own analysis. **Expanded –** Strengthened data quality management through Informatica (our data governance platform), completing 1,240+ new data quality checks across our datasets, providing a quantitative measure of quality that we monitor and use to establish improvement plans where required. **Existing –** We provided strong transparency for stakeholders by continuing to improve existing Data Quality Assessments for our ODP datasets, providing clearer information on data quality and supporting more confident use of our data. **Existing –** Provided strong assurance of accuracy and neutrality through data quality assessments, data triage assessments, improved metadata, and expanded use of Informatica.

2.1.1 – Sharing comprehensive planning, market, and operational data, and additional data for stakeholder value

Datasets, dashboards, and tools we have released this year:

Name	Customer/Stakeholder impact
Market Information	
Flex Landing Page	Central hub for flexibility, containing our main flexibility datasets and visualisations to help stakeholders understand market activity.
Flexibility Dispatch	Half-hourly dispatch instructions enabling stakeholders to identify volumes, capacity, and types of flex dispatch to support new flex provision.
Distribution Network Options Assessments	Options Assessment results and constraint descriptions for each location, with interactive maps, to inform choices for stakeholder planning.
Distribution Network Options Assessments Polygons	Provides a map-based view of planned reinforcement from the Distribution Network Options Assessment (DNOA) dataset in a more user-friendly visual format.
DFES Totals by Building Blocks (SPD/SPM)	Provides forecasts for heat pumps and EVs aggregated to the LA level, enabling stakeholders to incorporate our LCT forecasts into their own planning.
Customer Connections Profile (HV Feeder, Census Area, Primary Substations, LV Transformer)	Enables understanding of demand and generation types at various levels of aggregation, and existing connection profiles for use in models and energy planning.
Connections Data – Volumes by Market Segment	Users can identify areas and voltage levels with high or low connection application rates, highlighting potential areas for investment.
Network Planning Data	
Non-Firm Connections Insights	Half-hourly MVA measurements for primary substations and GSPs. Allows users to build load duration curves to identify areas for non-firm DER connections.
Historical Substation Demand Curve	Provides historical half-hourly demand for the last three years. Users can build demand profile curves for network modelling and identify periods of maximum demand.
SPD, SPM & SPT GIS Shapefiles (Line Assets, Point Assets)	Asset data in GIS format for Distribution and Transmission licences by LA, which was the most popular data request this year.
Secondary Substation Polygons	Asset data in GIS format for SPD and SPT licence areas. Users can download and map network assets by LAs area.
LTDS CIM (SPD, SPM)	Structured CIM of the LTDS, enabling consistent data exchange and network modelling across DSOs. Allows power system engineers to run more accurate and detailed load flow analysis.
Operational Data	
Network Flows: SPEN Boundaries	Half-hourly boundary flows between our licence areas and other DNOs/TOs. Allows users to include boundary flows in studies.
Capacity Management System Data	Captures daily aggregated generation losses from curtailment under ANM and LMS schemes. Helps users understand curtailment levels throughout the year.
Historical Feeder & Substation Utilisation (SPD/SPM)	Annual utilisation and capacity for transformers and 11kV feeders on SPD. Helps users understand available capacity and feeds into network heatmaps.
Secondary Network Visibility Dashboard	Smart meter and LV monitoring data on an interactive map to identify areas with greater network visibility. Supports demand forecasting and analysis of LV monitor coverage.
Carbon Accounting per GSP (SPD/SPM)	CO_2 equivalent emissions for substations and GSPs, combining NESO carbon intensity data with historical MW usage, showing the carbon impact of the network.
Historical Substation Demand Curve	Historical half-hourly demand enabling users to create substation demand curves for modelling or to identify areas and times suited to flexibility products.
Distribution Network Live Outages	Provides live outage data for LV and HV distribution networks. Used by stakeholders to monitor network state and assess the impact on their own assets.
Additional	
Glossary	Definitions, descriptions, and acronyms for terms used across the portal. Added following stakeholder survey feedback to improve data understanding.
Substation Naming Reference Table (SPD/SPM)	Unified reference for substation naming across datasets, enabling users to link and cross-reference substation data across datasets with varying name formats.

Dataset Dashboard or Tools

Highlighted rows indicate datasets added in response to stakeholder requests.

2.1.1 – Sharing comprehensive planning, market, and operational data, and additional data for stakeholder value *continued*

Case study: How a global telecommunications provider is using our live outage data in practice

The datasets we have released this year, through our API functionality, are creating direct operational value for stakeholders by helping them automate decisions and respond more effectively to network events. Through engagement with a global telecommunications provider on our network, we learned that it uses our API-enabled live outage data to identify when site issues are caused by power outages rather than telecoms faults. This helps avoid unnecessary site visits and supports service management across around 30,000 sites each year. This enables faster decision-making, reduces avoidable field activity, and helps maintain service availability for end users.

This engagement showed how stakeholders use our data in practice and where further value can be created. The telecommunications provider identified additional datasets that would support its operations, including more historical outage data for post-event analysis and more granular geographic data, such as substation service area polygons, for better spatial planning. We utilise this kind of engagement to help us understand stakeholder needs and target further improvements in the data we provide. It also shows how our accessible, machine-readable operational data supports day-to-day operations and easier system integration, and how important our work supporting the development of the National Electricity Outage Platform is for more standardised outage data to support customers working across DSO licence areas.

2.1.2 – Considering and using third-party data, including smart meter data

Use of smart meter data: Smart meters have been part of SPEN's open data offer for several years. Building on this, this year, we published four smart meter penetration datasets on the ODP as an interactive map, helping stakeholders understand coverage and potential use cases, and created a dedicated smart meter catalogue on the ODP to improve how stakeholders access this data. Internally, we use smart meter data to strengthen LV visibility and improve both planning and operational decision-making, as explored below.

Case study: How our use of Smart Meter data in NAVI provides Industry-Leading Network Visibility

As LCTs grow, customer demand becomes more dynamic, and the LV network becomes harder to plan and operate using assumed asset utilisation alone. NAVI helps us respond to that challenge by bringing together smart meter, network monitoring, and broader asset data into a single digital twin of our distribution network. Covering the full network from customer connectivity to the transmission interface, NAVI gives us a more complete and timely view of network conditions and enables analysis across multiple time scales. This matters because better visibility helps us make faster, better-targeted, and more transparent decisions for current and future customers. NAVI is the industry's only digital twin with a single model of the whole network, which is updated nightly, enabling it to 'self-heal' data quality.

Historical analysis: We use historical smart meter and monitor data to understand how our network is actually being used, rather than relying only on assumed asset utilisation. This improves our understanding of loading patterns at lower voltages, and strengthens the data foundations for forecasting, capacity assessment, and future flexibility planning. We have also improved the granularity and timeliness of this data, including work to access disaggregated smart meter data in support of LCT identification.

Near real-time visibility: We have significantly increased the frequency of smart meter voltage data refreshes, moving from weekly to nightly collection across our entire smart meter population. This gives us a much more up-to-date view of changing LV conditions, improves our understanding of emerging constraints and available headroom, and strengthens our ability to use smart meter and LV monitor data together to support more timely operational visibility and flexibility-ready network management.

Better Asset Decision-Making: Smart meter and monitor data, particularly from LV monitors, gives us more granular network visibility. This strengthens ENZ planning, supports reinforcement and replacement decisions based on actual rather than assumed asset use, and helps identify where flexibility or reinforcement will be needed, reducing unnecessary investment and improving cost efficiency. NAVI is also now improving how internal connections are processed. The first iteration of our Internal Connections tool has replaced WinDebut, enabling our Connections Team to complete power analysis within NAVI to assess applications, confirm whether connections can be accommodated, and identify reinforcement requirements where they cannot. This reduces processing time, increases the volume of studies that can be completed, and improves process resilience as older tools are retired.

User-led whole-system planning: Third-party data is essential to ensure our network planning reflects real development ambitions across our licence areas. This year, our Strategic Optimisers strengthened how we capture planned and emerging schemes from LAs, regional bodies, and heat, transport, and industrial customers through our RSP, so they can be factored directly into planning. We use this as a key input to our DFES, alongside third-party sources including tRESP, weather, census, and postcode-based data. This supports a shift towards more coordinated, place-based energy planning, where our role is not only to respond to change, but to help enable it through better visibility of stakeholders' plans.

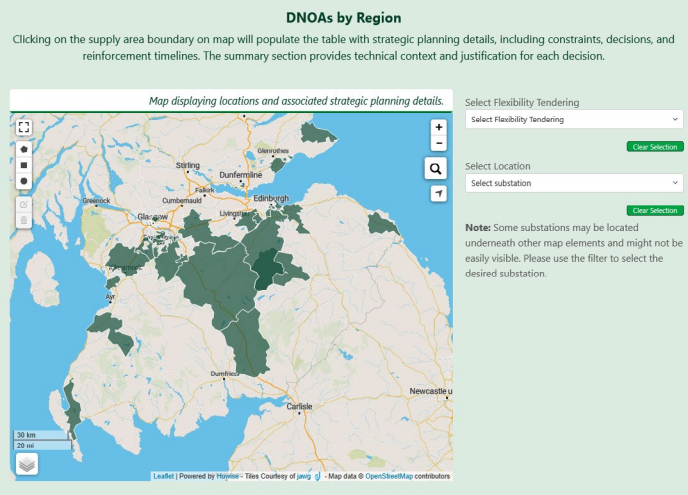
2.1.3 – Sharing underlying methodologies and other insights

Data quality assessments for datasets: To improve transparency on dataset design and content and help stakeholders understand how to use our data correctly, we have published Data Quality Assessments on the ODP, giving stakeholders clearer visibility of dataset completeness, validity, and other quality measures. These assessments are updated regularly and are a key part of how we help stakeholders interpret data appropriately and understand its strengths and limitations. We have also consolidated supporting documents within the ODP so stakeholders can access data and the information needed to interpret it in one place. This wider supporting information includes risk assessments for all relevant datasets, including primary datasets. Method statements have already been published for primary datasets, explaining the assumptions, processing steps, limitations and intended use, with method statements for the remaining datasets to be published by June 2026.

2.1.3 – Sharing underlying methodologies and other insights *continued*

Going beyond raw data and providing insights: In response to stakeholder feedback requesting more practical, decision-focused insight beyond raw datasets, we expanded our feature pages and dashboards so stakeholders can more easily turn data into decisions. We focused on four areas where users needed clearer visibility to support planning, investment, and operational choices: network headroom, flexibility opportunities, constraint resolution, and secondary network visibility. Four new tools now help stakeholders interpret and use our data more easily:

- Network Development Plan (NDP): high-level data and a map of available network headroom.
- Flexibility Activity: a view of flexibility activity and services, and supporting data and documents.
- DNOA: options and decisions made to address network constraints, including a map of DNOAs.
- Secondary Network Visibility: map of LV monitors and smart meter coverage, and aggregated consumption per substation.



Together, these tools make our data easier to understand, trust, and apply in practice, while supporting our wider approach of bringing data, methodology, risk information, and guidance together in one place. By combining dashboards, maps, and API-enabled datasets, we are also making it easier for stakeholders to use our information in their own analysis and workflows.

2.1.4 – Approach to improving data quality and the processes in place to address gaps in datasets and improve standards, ensuring accurate and unbiased data

Data quality management through Informatica: This year, to give stakeholders more reliable data, we strengthened our approach to data quality by expanding the use of Informatica to provide a more quantitative and repeatable basis for monitoring quality and targeting improvements. Over the latest reporting period, we completed 1,240+ new data quality checks across our datasets to identify issues, track performance, and put improvement plans in place where needed, with an average validity of 99.5%.

Ensuring data and information are of high quality, and are published in an accurate and unbiased manner: We ensure the data published through our ODP is of high quality by applying our Data Quality Assessment framework across all datasets. This framework assesses five core metrics – Validity, Completeness, Uniqueness, Timeliness, and Consistency – providing a consistent view of dataset quality and limitations for stakeholders. We have completed the first phase covering Validity, Completeness, and Uniqueness, and are extending published assessments to Timeliness and Consistency. We support the accuracy and unbiased nature of our data through consistent controls and governance, including:

- Method statements that set out assumptions, processing steps, and limitations
- Data triage assessments to ensure datasets are handled through a consistent process
- Improved metadata to reduce ambiguity and misinterpretation
- Expanded use of Informatica to monitor datasets systematically and identify improvement actions where needed.

This approach of multiple checks for data quality and bias, with assurance documents published on our ODP and clear links from the relevant dataset pages to the associated Data Quality Assessments, makes supporting information easier to find and strengthens transparency for stakeholders.

Improving dataset interoperability for stakeholders: We improved and aligned dataset descriptions on the ODP to clarify content, coverage, and limitations, helping stakeholders interpret data more consistently and reducing avoidable queries and misinterpretation. We also progressed a cross-dataset data model to align substation naming conventions, making it easier for stakeholders to combine related datasets (e.g. across connections and planning datasets) and integrate our data into their own analysis, tools, and workflows with less manual cleaning and reconciliation.

2.2 – Accessibility of Data

Criteria	Key Evidence
2.2.1 – Using DSO stakeholder engagement to tailor and improve our approach to data provision	**Existing –** Used the November 2025 Open Data Survey to capture structured feedback on accessibility, usability and future priorities, with 35 responses received. The results confirmed that we are on the right track, with 83% of respondents saying they would recommend the portal, while also identifying five clear improvement themes that directly shaped our 2025/26 delivery plan. **Expanded –** Adopted a more systematic stakeholder-led approach to data provision, launching a new, interactive Data Release Roadmap to set direction and provide visibility of what improvements are coming and when, supported by a clear "you said, we did" line of sight, through our "Open Data Survey Insights" video. **Expanded –** Expanded support material, including launching a new "Open Data Learning Hub", five new "How to" guides to reduce barriers to using data, and hosted a "Hands on with our Data" webinar to test usability in practice and capture stakeholder feedback for further improvements.

2.2 – Accessibility of Data *continued*

Criteria	Key Evidence
2.2.2 – Consistent and standardised use of common data formats and APIs for DSO stakeholders to automate their data collection	New – Long Term Development Statement (LTDS) network model has been published in the Common Information Model (CIM) format to improve standardisation and interoperability. Expanded – All data continues to utilise industry-standard API. This year, added API customisation on the ODP to make access easier for non-technical users. Existing – All datasets are available in machine-readable formats (CSV and JSON), and GIS data formats.
2.2.3 – Ensuring data is readily available in an easy-to-access location	New – Refreshed the ODP based on stakeholder feedback, and analysis of leading national and international ODPs. Adding interactive maps, feature pages, improved navigation, and accessibility with the Recite Me Tool. Expanded – Strengthened the ODP as the primary access point for SPEN's open data, in response to Panel feedback on disjointed access, by consolidating datasets, documents, and heatmaps in one place. This includes a dedicated category for data quality checks, which is already live on the ODP, with the remaining consolidation to be completed by June 2026.
2.2.4 – Consistent Application and consideration of industry standards	Existing – Applied Energy Data Taskforce principles and Ofgem Data Best Practice (DBP) to identify and deliver practical improvements to governance, discoverability, and supporting information.
2.2.5 – Our provision of network models	Expanded – Extended access to the LANIT network model from just LAs to transport stakeholders and regional governments, enabling wider place-based planning, including support for Transport for Wales. We also provide the 11kV and above network model via the LTDS and CIM to all stakeholders.

2.2.1 – Using DSO stakeholder engagement to tailor and improve our approach to data provision

How we gather insights from our stakeholders: We take a systematic, stakeholder-led approach to tailoring data provision to user needs. This year, we strengthened this through an active feedback loop combining our Open Data Survey, data requests and ODP mailbox, webinars, and DSO events, giving us both structured feedback on stakeholder priorities and practical insight into barriers to access and use.

At the end of 2024, we launched our annual Open Data Survey to assess the accessibility and usability of our ODP and identify improvement priorities for this year, as shown in the box below. The changes we made were a success, as demonstrated by this year's survey, which gathered responses from 35 participants across various stakeholder groups, including network operators, local authorities, consultants, academics and more. While 80% stated they would recommend the portal to others, only 60% reported being satisfied with it. Feedback consistently identified access and usability as primary concerns, suggesting that, although the portal was perceived as valuable, these issues acted as material barriers to effective use for a substantial share of users. Notably, nearly half of respondents highlighted a need for either additional datasets or improvements to existing ones, pointing to clear stakeholder demand for both expanded data provision and ongoing enhancement of the ODP's current offer. These insights highlighted five priorities for 2025/26: more maps and visualisations, easier navigation, improved searchability, greater visibility of existing feature pages and tools, and clearer forward visibility of planned releases. We supplemented this with insight from our Open Data Request process and portal mailbox, resolving 300+ requests for additional data, clarification, and support, and using these to identify recurring barriers and improvements.

How we addressed survey feedback:
- Added maps and visualisations
- Better dataset navigation with extended dataset tables and filtering on the ODP
- Improved search ability with new themes and categories
- Shared roadmaps through more channels
- Added feature pages to our ODP homepage and a dedicated drop-down menu

How we have tailored data provision to stakeholder needs: We have used this feedback directly to shape our Open Data Release Roadmap, drawing a direct link between what was requested and what we delivered. This focused delivery on the five most requested datasets, including live outages, connections, flexibility, and network options assessment data as explored in 2.1.1, alongside the feature pages, dashboards, maps, filters, and visualisations, stakeholders told us would improve the ODP, as explored in 2.2.3. Our Open Data Release Roadmap provides stakeholders with clearer visibility of what improvements are coming and when, and supported this with an "Open Data Survey Insights" video showing the changes delivered in response to feedback. We have also updated the Roadmap to be interactive, and will update it quarterly, giving stakeholders clearer visibility of available data, planned changes, and sources of support, while making the ODP easier to navigate and use.

To ensure our data provision remains aligned to stakeholder needs, our forthcoming DSO Data Strategy will set priorities for the rest of ED2 and into ED3. It has been shaped by our ED2 stakeholder engagement and targeted engagement with different stakeholder personas, focusing on how data is used, the barriers stakeholders face, and how needs will evolve. This will help keep our future approach stakeholder-centric and responsive.

Expanding learning resources to enable stakeholders to use our data: To help stakeholders access, understand, and use our data more effectively, we expanded the support available alongside the ODP in response to requests for more practical guidance. This included launching a new Open Data Learning Hub covering key topics such as portal navigation, API use, and how to use our data more effectively, with five new how-to guides and clearer API documentation. We strengthened this further through our Hands-on with our Data webinar, which let stakeholders test the new portal experience, see how datasets can be combined in practice, and provide feedback on further improvements. We are now using those insights to shape the next iteration of our Data Release Roadmap, ensuring stakeholder engagement continues to shape both our data provision and the support around it.

2.2.2 – Consistent and standardised use of common data formats and APIs for DSO stakeholders to automate their data collection

Providing data in machine-readable formats: This year, we continued publishing all data in machine-readable formats, including Excel, CSV, and JSON, and GIS data in GeoJSON, Shapefile, KML, FlatGeobuf, and GPX. We also published the LTDS network model in CIM format to improve the standardisation and interoperability of network data with other DSOs, supporting third-party use and integration.

Improving our extensive API access: To help stakeholders integrate our data directly into their own tools and automated workflows, all datasets are available through an industry-standard API. Usage remains high, with more than 3.2 million API calls in the last year. This year, we also improved how stakeholders interact with our APIs and improved interoperability by enabling users to generate customised API code directly from dataset page on the ODP. We have enabled stakeholders to build custom API code based on their specific needs without needing technical abilities. This creates a plug-and-play API solution which can be generated in cURL, JavaScript, and Python.

2.2.3 – Ensuring data is readily available in an easy-to-access location

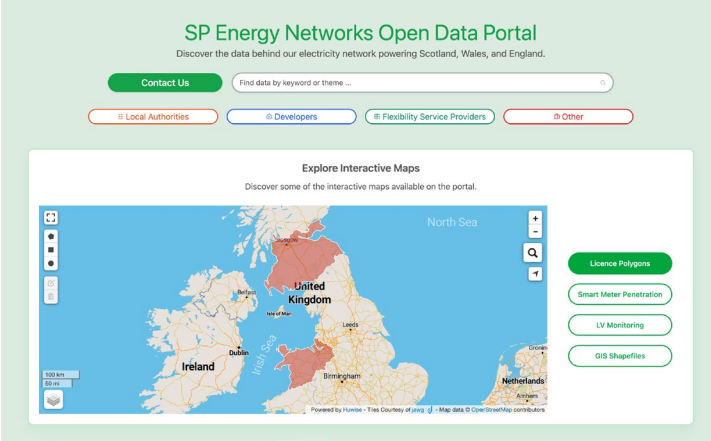
This year, we transformed our ODP through a full homepage redesign to make it clearer, more intuitive, and better aligned to how stakeholders use our data in practice. The redesign drew on feedback gathered throughout ED2, a review of other networks' ODPs and leading international examples, and targeted stakeholder testing across different stakeholder personas and technical abilities. It responded directly to feedback on navigation, discoverability, visibility of key tools and feature pages, and the need for more visual ways to explore data, and we will use ODP usage data to inform future improvements. In response to Panel feedback that data access felt disjointed, we strengthened the ODP as the primary access point for SPEN's open data by working to consolidate datasets, supporting information and heatmaps in one place by June 2026. As the first step in this consolidation, we have already created a dedicated data quality category, which is now live on the ODP.

Improved design and accessibility:
- Redesigned homepage with improved user journey and overall UX/UI performance, helping stakeholders find relevant datasets more quickly and navigate the portal more easily.
- Feature pages added to the homepage, and improved dropdown menus for easier navigation.
- Recite Me accessibility tool to support inclusive access and allow a customised experience.
- Glossary of terms with pop-up definitions in data descriptions for easier understanding.
- Improved dataset descriptions to improve understanding and usability.

More maps and visualisations:
- A dynamic homepage map providing a visual route into network data across our regions.

Easier dataset navigation:
- User-driven categories and simplified navigation to help users find relevant content faster, with updated themes and keywords to support more efficient use of datasets.
- New data marketplace and intuitive data catalogue, with all related datasets in one place.
- Upgraded API experience, with faster performance, clearer documentation, and an API customisation window to make it easier for stakeholders to integrate data into workflows.

Greater visibility:
- Improved visibility into the full data offer, covering both fully open datasets and those that require a shared licence, so stakeholders can understand what is available and why.



2.2.4 – Consistent application and consideration of industry standards

We continued to apply industry standards consistently across our data offer, with Ofgem DBP at the core of our data strategy and stewardship of the ODP. Our Digitalisation Action Plan (page 30) sets out how we meet the 11 DBP principles and the further improvements we are making to increase maturity, including stronger governance, better metadata and discoverability, more supporting information, and a transparent roadmap for future improvements.

We also align with the Energy Data Taskforce principles. We support Digitising the Energy System by publishing new data, improving existing data quality, and delivering coherent digitisation and data plans. We apply the Presumed Open principle through discoverable, understandable data on our ODP, strong data access and aggregation structures across SPEN, and secure, resilient data publication supported by structured data triage and alignment with the ENA DSO Data Sharing and Data Triage playbook.

2.2.5 – Our provision of network models

We provide network models through two complementary routes, designed to meet different stakeholder needs:

- For all stakeholders, we publish the 11kV and above network model through LTDS, and now including the CIM network model dataset, available via our ODP and refreshed annually.
- For local authorities, we provide a dedicated network model interface tool through LANIT, which was extended to regional governments and transport organisations this year. LANIT has been used to assist 21 LAs with optioneering assessments, with full details in 4.1.3. LANIT provides a map-based view of the distribution network for LCT optioneering and the expected network costs, supporting place-based planning and local decarbonisation strategies. This year LANIT won the Best Innovation: Software and Services award at the Scottish Green Energy Awards for helping LAs and regional bodies plan for a decarbonised future.

3. Flexibility Market Development

This year, we concentrated on expanding flexibility activities and improving our market arrangements, in response to last year's Panel feedback. We have seen significant market growth driven by our Flexibility Team's Persona-based Engagement Strategy, with the following changes from last year:

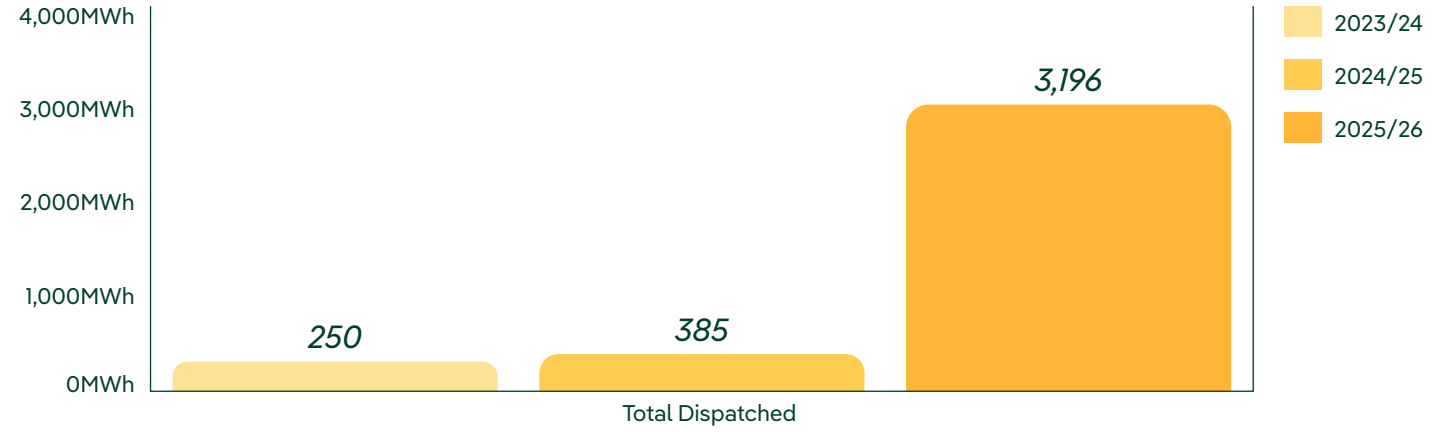
17.6x *increase in distribution flexibility capacity available from 325 MW to 5.7 GW*

4.1x *increase in registered providers from 9 to 37*

3.3x *increase in registered assets from 33,394 to 110,894*

We have further matured our market and enhanced how our markets function by developing procurement and market design to better meet FSPs' needs and capabilities. This includes expanding StormFlex for severe weather response, increasing available capacity from a single site with 20 MW to multiple sites with 201 MW, introducing Day-Ahead Demand Turn Up markets, and strengthening LV management and social flexibility. We have also upgraded tendering and dispatch with our new flexibility tendering platform, ElectronConnect, including enhancing the platform to meet FSP needs, enable a seamless transition between platforms for FSPs, and built in forward looking interoperability. We are improving the matching of flexibility to constraints by integrating FSP asset data into our digital twin, NAVI, and investigating the impact of flexibility on the network. We strengthened engagement through close FSP relationships, over 300 one-to-one meetings, and 35 events hosted and attended, including our Flexibility Summit in Liverpool, supported by a tailored engagement strategy.

Growth in total flexibility dispatched



3.1 – Design of distribution flexibility products, contracts, and processes

Activities	Key Evidence
3.1.1 – Standardising our flexibility services, contracts, and qualification criteria. Implementing the full Open Network deliverables and improving based on stakeholder feedback	New – Further standardisation through early adoption of Elexon's upcoming Flexibility Market Rules. Expanded – Fully standardised products, contracts and processes, implementing all Open Networks deliverables. Expanded – Improved Open Networks deliverables by using FSP persona insights to tailor contracts beyond a "one-size-fits-all" approach, and by working with FSPs to surface barriers and drive contract updates through the Elexon working group.
3.1.2 – Following and setting industry industry-leading benchmark for products, contracts and processes	Industry leaders – Expanded StormFlex to support storm response and sharing learnings with NGED, NPG, and SP ENW, to drive wider adoption. New – Introduced Day-ahead Demand Turn Up (building on month-ahead) to increase flexibility utilisation at shorter timescales.
3.1.3 – Undertaking extensive engagements with stakeholders to identify and address key issues hindering flexibility market development	Industry leaders – Released the industry's first Flexibility Market Engagement Strategy, built around six market personas to reflect different FSPs' blockers and needs. New – Created a sector-wide forum at our Flexibility Summit, with 106 participants, to improve the FSPs experience. Expanded – Our engagements combined breadth (35 events and four webinars) with depth (over 300 one-to-ones) to remove provider-specific barriers. With insight from engagement we adjusted tendering patterns, launched Day Ahead Demand Turn-Up, developed persona how-to guides. Further insights allowed us to identify improvements to the Standard Flexibility Agreement and work with Elexon to incorporate them.

3.1 – Design of distribution flexibility products, contracts, and processes *continued*

Activities	Key Evidence
3.1.4 – Unlocking the value of flexibility and energy efficiency in nascent areas	New – Begun integrating flexibility asset data with our industry-leading digital twin, NAVI, to identify new opportunities using real-time data. New – Introduced Demand-Turn Up Day Ahead markets to unlock additional flexibility in three new areas in Scotland. Enabled five social housing estates to participate in flexibility, with additional households being added in the Summer. Expanded – Identified 50 sites, up from 23 last year, where LV flexibility can be utilised to address network constraints, providing Options Assessment with additional non-build measures.
3.1.5 – Working to enable secondary trading of flexibility and curtailment obligations	Existing – Approach to enabling secondary trading/curtailment obligation reflects a lack of FSP demand for this market; we are using ongoing engagement to understand when demand will arise and planning accordingly.

3.1.1 – Standardising our flexibility services, contracts, and qualification criteria, and implementing the full set of Open Network deliverables and making improvements based on stakeholder feedback

Standardising flexibility design with upcoming market requirements: This year, our focus has been on aligning our flexibility market with Elexon's Market Rules, so that providers have a clearer, more consistent route into our markets as the national framework is implemented. We have worked with Elexon in various working groups, and the table below shows our alignment with all the rules, except primacy, which is still under development by the industry. This builds on last year's implementation of the ENA Open Networks deliverables, the adoption of the V3 Standard Flexibility Service Agreement, and continued procurement of the standard products in the ENA Standard Flexibility Product List.

Improving Open Network Deliverables based on stakeholder feedback: We work closely with FSPs to identify practical barriers and improve service design, participation steps, and specific contractual clauses that block participation, as set out in 3.1.3. Drawing on our market quantification exercise, we are tailoring the Standard Flexibility Service Agreement v3.0 to the needs of six market personas, and sharing these learnings through Elexon's Working Group on the Evolution of the Standard Agreement. Specific changes include:

- Local Authorities: Drafted a Public Sector-friendly flexibility service agreement, which we are proposing to Elexon working groups.
- Aggregators: Removed the site visit clause, eliminating the need to inspect customer homes. This has allowed Octopus and Fuse to join our markets.
- Operational Flexibility & Generation Assets: Introduced a new Operational Flexibility tendering process, including optional testing with our Control Room to give provider confidence in technical participation and safety arrangements, which has been a significant enabler of participation by 40MW+ assets.
- Domestic customers: Limited liability for small-scale assets to the value of their contract, ensuring they are not subject to the same £250,000 liability large FSPs are subject to.

We were the first DSO to implement Elexon's new baselining methodology, enabling FSPs to use simplified baselining earlier and reducing the time required to calculate more complex baselines, supporting participation from larger volumes of assets. We were able to test Elexon's Alternative Baselining Methodology before the market rules went live, identify practical barriers and restrictive contractual clauses ahead of full deployment. We shared provider utilisation rates and wider learnings with SP ENW, SSEN, and NGED through the Elexon working group to support more informed industry-wide implementation. In terms of operational flexibility, we developed dynamic pricing tools, in the absence of a common pricing methodology, which enabled us to offer more competitive combinations of availability and utilisation prices, helping to remove commercial barriers for large-scale capacity and Balancing Mechanism-participating assets, while reducing perceived risks linked to contract liability clauses. We shared these approaches through knowledge-sharing sessions with other DSOs.

Flexibility Market Rule	Fully implemented	Inclusion in market catalogue	KSI produced
FMR-CRM-Carbon Reporting Methodology	✓	✓	N/A
FMR-E2E-End to End process	Implementing	Implementing	✓
FMR-GLO-Market Facilitator Glossary	✓	✓	✓
FMR-PD-Product Definitions	✓	✓	N/A
FMR-PQC-Pre-Qualification Criteria	✓	✓	✓
FMR-PR-Primary Rules	Implementing	Implementing	Implementing
FMR-RSR-Revenue Stacking Requirements	✓	✓	✓
FMR-SBM-Standard Baselining Methodologies	✓	✓	✓
FMR-SMD-Sub-Market Definititions	✓	✓	✓
MR-VSM-Verification & Settlement Methodology	✓	✓	N/A

3.1.2 – Following and setting industry-leading benchmarks for products, contracts and processes

Moving beyond baseline products: StormFlex, our industry-leading BAU flexibility service for severe weather response, was strengthened this year to improve customer resilience by increasing standby capacity from one FSP to multiple providers and diversifying generation away from sole reliance on hydroelectric power to improve reliability. Working with providers, we refined the service to reflect real-world availability and commercial and technical constraints, giving us over 201 MW on standby during this year's named storms, compared with 20 MW last year. This increased network resilience meant that during Storm Amy, StormFlex could have brought 250,000 customers back on supply faster than through network repairs, had they been required after damage and outages. This is a significant increase over the 15,000 customers restored during Storm Darragh. We are also sharing our contracts, deployment processes, and learnings with NGED, NPg, and SP ENW to support their development of similar products.

We also introduced Demand Turn Up Day-Ahead markets in response to stakeholder requests for shorter-timescale opportunities, enabling three new regions in Scotland to participate in flexibility markets. Two new FSPs initially joined, and the participation of existing FSPs increased, including Octopus Energy, which is delivering 10 MW of customer-led flexibility. This is enabling domestic customers to participate in flexibility markets and providing them with more affordable energy. Additionally, this is enabling more Industrial and Commercial (I&C) customers to participate in flexibility. For example, one of our I&C customers used Demand Turn Up revenues to switch off its usual gas-fired CHP generation and instead consume electricity from the grid, which is in an area where electricity is largely wind-generated. This helps us manage generation and demand locally, reduces the customer's carbon emissions, and increases I&C utilisation of renewable electricity.

The effect of flexibility on transmission: This year, we began a detailed programme of work using NAVI's network visibility and analysis to understand how flexibility across the distribution system affects the wider network, including transmission, across products, asset types, voltage levels, and timeframes. The aim is to understand what type, volume, and location of flexibility is needed to deliver a given network impact, so future procurement is more targeted and effective. Initial analysis of HV Month-Ahead tenders showed a clear relationship between dispatched flexibility and measurable impacts on the transmission network, particularly from generation and I&C assets, but raised further questions about the effectiveness of LV flexibility from aggregated domestic LCTs on the transmission network. We are also sharing findings with other DSOs and leading a working group to develop a unified methodology for assessing system impacts from distribution flexibility.

3.1.3 – Undertaking extensive engagements with DSO stakeholders to identify and address key issues hindering flexibility market development

Improving our understanding of FSPs needs to address barriers to flexibility market development: This year, we became the first DSO to launch a Flexibility Market Engagement Strategy. We developed persona-specific guidance and Service Agreement adjustments, as discussed in 3.1.1, and formalised a closed feedback loop, supported by measurable activity. This included increasing one-to-one meetings from 109 last year to over 300 this year, and persona-based growth targets such as increasing I&C providers from 110 MW to 500 MW by 2028. The Strategy was informed by a market quantification exercise to analyse connected flexible resources on our network. It moves beyond a generic industry-wide approach to a persona-led model based on six flexibility personas, focused on removing barriers and improving access to both our DSO flexibility markets and the wider flexibility market.

We strengthened our understanding of household flexibility by independently polling 2,500 customers to support a more joined-up approach to consumer-led flexibility. This quantified the scale of connected assets and existing market participation, in line with DESNZ ambitions for a five to six-fold increase in consumer-led flexibility gigawatts. A key finding of the study was that 86% of respondents would participate in flexibility, but only 33% currently do. The key barriers, and how we are addressing them, are:

Barrier	Action	Purpose
Financial benefits are too low	Assess current suitability of Common Evaluation Methodology (CEM) tool for valuing flexibility	Create a more up to date view on pricing of markets
Complicated schemes	Creation of digestible flexibility example scenarios	Simplify the complexity of flexibility for the end user and demonstrate its key benefits
Low awareness of flexibility, and low engagement from LCT and smart meter owners, despite interest	We will engage electricity suppliers to partner on flexibility schemes and develop an information pack for LCT and smart meter customers.	Leverage suppliers' market reach and growing LCT and smart meter uptake to promote flexibility and deliver our schemes

Moving beyond broad engagement to meaningful support: The backbone of our engagement is over 300 one-to-one meetings with FSPs, where we are the enablers, providing advice and problem-solving, understanding FSPs' assets, constraints, and commercial requirements, and guiding them through onboarding, contracting, and delivery. This supports a continuous process of shaping market delivery end-to-end through direct feedback, as shown by the FSP quote opposite.

Facilitating impactful industry-wide events: We pair one-to-one engagement with wider channels to reach more stakeholders and ensure consistent communication. This creates multiple routes for feedback and reduces the risk that only established providers shape market design. Events are used to discuss stakeholder needs, while webinars provide major market changes. We hosted and attended more than 35 events, from the Glasgow Innovation Conference to agricultural shows, and four webinars on market updates, participation routes, and common market barriers.

"The one-to-one support provided throughout onboarding, participation, and settlement has been key to enabling our market involvement. The collaborative approach and direct engagement have helped simplify processes, resolve challenges quickly, and ensure we can participate with confidence and clarity. This has enabled us to scale our energy flexibility proposition and, with SPEN support, become a market leader in this sector."

Electric Miles, EV aggregator

3.1.3 – Undertaking extensive engagements with DSO stakeholders to identify and address key issues hindering flexibility market development *continued*

Case study: Our Flexibility Summit in Liverpool

In September, we hosted our first Flexibility Summit in Liverpool, a sector-wide forum bringing together 106 participants including DESNZ, Elexon, FSPs, LAs, NESO, NPg, and Ofgem, who all participated in or led breakout sessions, and NESO inviting additional stakeholders to join the event. The Summit increased awareness of flexibility opportunities and gathered feedback on provider journeys. Sessions included A Day in the Life of an FSP and The Future of Flexibility, alongside breakout sessions on topics including NESO opportunities to the role of LAs and community energy in flexibility. It was designed to support open dialogue, allowing stakeholders to share needs, test assumptions, and shape next steps collaboratively. Below is representative feedback from attendees and our actions on them:

Feedback	Action
FSPs need to be involved in the development of Elexon rules to ensure their needs and challenges are reflected in market rules.	We are consistently documenting FSPs' feedback on Elexon's market rules and the Standard Flexibility Agreement, and representing these needs in working group discussions.
Day-ahead markets need to be tailored to personal needs, rather than a continuation of other DSOs' products. For many FSPs, Month-Ahead is still an ideal time frame.	Tailoring Day-Ahead products to meet personas' specific needs and availability, informed by our market quantification exercise, whilst continuing to run our Month-Ahead market.
Lack of long-term certainty, especially regarding ED3, about the role of flexibility.	Improving specific messaging regarding flexibility and ED3, with firm messaging delivered as the ED3 business plan is finalised this year.

3.1.4 – Unlocking the value of flexibility and energy efficiency in nascent areas

We have opened up opportunities by using industry-leading tools to identify nascent flexibility opportunities: We strengthened our offering of LV flexibility to address network constraints, expanding from 23 zones last year to 50 this year. This enables flexibility to be utilised as part of the toolkit for managing short- and long-term constraints on the LV network. This was enabled by NAVI, our industry-leading digital twin and the only connectivity model covering all distribution voltage levels in one system. We improved LV visibility through additional LV monitors and harnessing higher smart meter penetration, allowing real-time data to identify flexibility opportunities where network reconfiguration cannot resolve constraints. This year, we began the process of integrating flexibility asset data into Netview, NAVI's map-based visual representation of the network. This will allow us to use real-time data to match flexibility to constraints on HV and LV feeders and transformers, to test and model flexibility interventions for constraints, LV flexibility, and assessment of cross-voltage impacts. We have developed a process map of how district staff can utilise flexibility to manage the network at a local level, and will soon be able to provide the Netview interface.

Our Growth Strategy for emerging FSPs

FSP Persona Type	2025/2026 Capacity	End of ED2 Capacity Goal
Industrial and Commercial	110 MW	500 MW
Domestic Customers	93 MW	300 MW
Community energy groups	0 MW	20 MW

Introducing Demand Turn Up Day-Ahead markets to unlock LV flexibility and meet our stakeholders' needs: This year, FSPs requested Demand Turn Up Day-Ahead markets, which have increased and diversified market participants, complementing existing Demand Turn Down markets. This enabled flexibility in three new areas in Scotland, new providers, including one I&C customer and Octopus Energy with 10 MW of domestic flexibility, and delivered 40 MWh of demand turn-up flexibility across 14 days.

Case study: SocialFlex

We are working with social housing, tariff providers, and smart electric storage heater retrofitters to enable vulnerable households to participate in flexibility, implementing Equiflex's learnings on the just transition into BAU activities, and showing how to implement its findings at scale. This will become a new flexibility product called SocialFlex, part of our move to a Social DSO. We identified Connected Response's retrofit of electric storage heaters with smart charger controls as a scalable, customer-friendly route to domestic flexibility. This BAU project enables households to take part in Demand Turn Up and Turn Down tenders, creating income that can reduce heating costs and fuel poverty, and improve comfort. We are currently working with five housing estates in Scotland, and will be expanding this with additional homes this year through SocialFlex. It also supports energy efficiency by incentivising smart electric storage heater retrofitting, while addressing key barriers identified by Equiflex, including low awareness, the limited suitability of turn-down-only products for vulnerable households, and the need for simpler participation routes. This opens a nascent domestic flexibility market, including rented accommodation, and provides an LV balancing tool.

3.1.5 – Working to enable secondary trading of flexibility and curtailment obligations

In one-to-one discussions, FSPs told us they do not want to participate in secondary markets at present. We therefore expect secondary trading of flexibility and curtailment obligations to grow later in ED2 and into ED3, rather than immediately, and are using ED3 planning to prepare the necessary infrastructure. We are continuing to work closely with providers to understand their future needs so that, when demand for secondary trading emerges, we are ready to support it.

3.2 – Facilitation of Market Access

Criteria	Key Evidence
3.2.1 – Enabling third parties to provide market support and platform services, and using non-proprietary systems	New – Finalised ElectronConnect as our flexibility tendering platform through competitive bidding. Expanded – Provided a specific Flexibility Data Catalogue, with additional datasets, for a total of 21 datasets to support other third-party services.
3.2.2 – Undertaking initiatives to improve market access and enable simple, cost-efficient participation	New – Reduced barriers with Demand Turn Up Day-Ahead markets, and simplified participation through streamlined onboarding. New – Made enhancements to ElectronConnect based on FSPs' feedback to reduce barriers and improve processes. New – Providing consulting support to FSPs, with tailored support to meet their specific needs. Expanded – Participation increased in 2025/26, with a 3.5x increase in FPSs participating in tenders, from 4 to 14, and a 3.3x increase in registered assets, from 33,394 to 110,894, representing a 17.6x increase in distribution flexibility from 325 MW to 5,707 MW. Expanded – Improved guidance materials and first DSO to release Flexibility Baselining Guidance.
3.2.3 – Our commercial arrangements with DER meet the GB System Operator's needs and improve coordination with the GB System Operators. We have no exclusivity clauses in our flexibility contracts. Ambitions for distribution flexibility for system optimisation	Expanded – Flexibility contracts include commercial provisions to support coordination with NESO, including required data sharing and visibility to enable stacking with NESO. Expanded – Working with NESO to develop joint solutions, including Demand Flexibility Service, Megawatt Dispatch, Local Constraint Markets, and Demand for Constraints. Enabling DER to support NESO, and progress ambitions for using distribution flexibility for whole systems optimisation. Expanded – ED3 strategy work is shaping the next phase of system optimisation, with further trialling and BAU embedding planned. Existing – All flexibility contracts do not contain exclusivity clauses.
3.2.4 – Providing operational data to the GB System Operator and other DSOs in a practical and accessible manner	Expanded – SPD ICCP link continues operation and only option NESO supports. An interim SPM ICCP link was proposed for Q1 2026, while an enduring solution was implemented. NESO rejected the interim solution, and the enduring solution will be completed by Q3 2026, subject to assurance activities. Existing – Continued operational coordination and data sharing through established channels, including Week 24, Week 50 and tRESP engagement.

3.2.1 – Enabling third parties to provide market support and platform services, and using non-proprietary systems

Our third-party flexibility tendering platform: A high-quality, non-proprietary, third-party tendering platform is vital to further strengthening and maturing our flexibility market, so this year we selected ElectronConnect as our new, non-proprietary platform. This followed an extensive procurement exercise across six bidders to identify the platform that best meets our needs and those of FSPs. We have since worked closely with ElectronConnect on enhancements to address these requirements, as discussed in 3.2.2 below.

Providing flexibility data to support additional third-party services:
We recognise the value third-party services bring to flexibility markets and support them through 23 datasets published under a dedicated Flexibility Theme on our non-proprietary, third-party ODP. As the national flexibility market matures, we expect these services to grow and plan to collaborate beyond data provision. For example, third parties could use our Flexibility Market Prospectus, SPD Flexibility Requirements, Flexibility Assets, Flexibility Dispatch, Flexibility Competitions, and Flexibility Bids datasets to build tools that estimate likely revenue, dispatch frequency, competition, and locational constraint exposure for an asset or portfolio.

3.2.2 – Undertaking initiatives to improve market access and enable simple, cost-efficient participation

Our targeted support to improve market access and simplify participation delivered our ever-largest increase in FSP participation to date. This year, auction participation increased 3.5x, from four providers to 14, registered assets increased by 3.3x from 33,394 to 102,894, available distribution flexibility rose 17.6x from 325 MW to 5,707 MW, and dispatched flexibility increased 7.3x from 385 MWh to 3,196 MWh (1,028 MWh in SPD and 2,168 MWh in SPD). We attribute this growth to the measures set out below, particularly as the number of flexibility locations available for tendering increased only from 40 to 63 (33 in SPD and 30 in SPM) this year:

Reducing barriers to flexibility markets: We launched Demand Turn Up Day-Ahead markets, allowing more FSPs to enter our flexibility market and existing FSPs to expand their offering, as discussed in 3.1.2, building on last year's work to introduce Month-Ahead markets, 0MW participation thresholds, and standard prequalification requirements.

We also expanded stakeholder engagement and tailored support programmes, underpinned by guidance documents that make market access easier, as explored in 3.1.3. Additionally, we began exploring longer-term firm flexibility contracts, including the potential to use multi-year flexibility budgets to support upfront asset installation in targeted areas, helping new providers overcome entry barriers and bring forward flexibility where it is most needed.

Supporting FSPs' market participation through tailored stakeholder engagement: As discussed in 3.1.3, we greatly expanded our stakeholder engagement this year, focusing on building personal relationships with FSPs and tripling one-to-one engagements. We developed a customised 'consulting' support approach, tailored to the specific needs of FSPs, and used this information to adapt flexibility service agreements to the challenges and needs of FSP personas.

3.2.2 – Undertaking initiatives to improve market access and enable simple, cost-efficient participation *continued*

Increasing our library of guidance materials: Expanded our guidance and supporting materials for FSPs, added a dedicated flexibility category and feature page on the ODP with 21 flexibility datasets, developed in consultation with FSPs, helping to reduce barriers to entry, including:

- Flexibility Market Prospectus, providing clear market signals for the year, and extensive data on constraints forecasts for the next three years, helping FSPs plan their operations.
- Operational Flexibility Participation Guidance, which provides a detailed guide to how the flexibility process takes place from the tendering process to dispatch, billing, and payments.
- Flexibility Market Engagement Strategy, developed through a market quantification exercise of the flexibility market, provides tailored advice on how to participate in the flexibility market and how we are engaging with six FSP personas, such as domestic suppliers, generators, and LAs.
- Specific flexibility market participation guidance for LAs and community energy groups.

Shaping ElectronConnect to meet FSPs' needs: Our newly launched flexibility tendering platform is designed to meet FSP needs and simplify participation in our markets, and has been shaped based on our knowledge of their needs through our extensive engagement programme. Following an extensive procurement process, we selected Electron's ElectronConnect platform and have since worked closely with Electron to enhance it further for both ourselves and FSPs. Improvements to date include:

- Automated CMZ alignment: using meter point administration numbers (MPAN) and mapping files, FSPs' assets are automatically confirmed if they are in the correct CMZ for a tender, reducing the time providers spend analysing tenders and technical documents.
- Automated registration of FSPs assets: reduce manual steps for FSPs, simplifying processes and reducing duplication of effort and time.
- Half-hourly smart meter consumption data: improved and more efficient reconciliation on how an FSP has performed against an accepted flexibility trade bid. This is ultimately used to determine that an FSP is paid the correct amount.
- Automated bid acceptance and dispatch management: FSPs receive automated notification of bid acceptance, dispatch signals, and invoicing via API, allowing them to further streamline and automate operations.

3.2.3 – Our commercial arrangements with DER meet the GB System Operator's needs and improve coordination with the GB System Operator

Our commercial arrangements with DER facilitate coordination with NESO: All our flexibility contracts are non-exclusive and include stacking provisions, providing the commercial framework for collaboration with NESO and DER. We are working with NESO to strengthen cooperation and expand access to our markets, including:

- Demand Flexibility Service: allowing domestic customers to participate in demand turn-up flexibility, and providing rewards via their energy suppliers.
- Megawatt Dispatch: using distribution-connected DER to help NESO balance regional transmission constraints by increasing production.
- Local Constraint Markets: enabling NESO to manage constraints on the network by purchasing demand turn-down flexibility in distribution markets.
- Demand for Constraints: supporting NESO to provide discounted tariffs to flexibility providers to increase demand, allowing NESO to offset excess generation by renewable energy generation, which would otherwise be paid to curtail generation.

As explored in 3.1.2, we are using NAVI's industry-leading capabilities to study the relationship between dispatched flexibility and measurable impacts on the transmission network. This will help the industry understand how consumer-led flexibility can relieve transmission constraints, improve understanding of distribution-to-transmission interactions, and support more effective flexibility products. Additionally, we work with NESO and signpost newly registered FSPs, particularly I&C providers, which are more suited for transmission markets, helping them access stacking opportunities more quickly and supporting a more joined-up whole-system route to market.

Ambitions for distribution flexibility for system optimisation: We are working internally and with NESO to use flexibility for whole-system optimisation. We are progressing the programmes discussed above with NESO, to support wider systems optimisation, supported by our flexibility contracts being non-exclusive and explicitly supporting stacking. A key part of our ED3 planning is on the structures and policies to support flexibility for system optimisation. It is our view that DSOs can play a key role in unlocking Consumer Led flexibility through our Market Engagement strategy, particularly for personas that require bilateral engagement at a local level in order to address bespoke barriers to market participation.

3.2.4 – Providing operational data to NESO in a practical and accessible manner

Communications with NESO: We continue to share operational information with NESO through standard mechanisms such as Week 24 and 52, the Regular Reporting Pack, and tRESP engagements, and have working contact between our control rooms for information sharing. This year, SPD and SPT's SCADA operating system, PowerOn, were integrated, linking SPD directly into the Inter-Control Centre Communication Protocol (ICCP) link, which NESO has confirmed meets their needs and is transmitting the following data:

- Operational data for large distribution-connected generators (one MW or greater), including plant status, analogue values, wind speed, and available power.
- Plant positions and analogue values at GSP level, including 33kV feeder breaker data and grid incomer information, giving NESO greater visibility of network conditions at key interfaces.

We are collaborating with NESO to complete the SPM link by Q3 2026. We offered an interim solution for an ICCP connection in early 2026; however, NESO declined and requested that we only implement the long-term solution. Further details on our ICCP links can be found in 5.1.4.

4. Options Assessment and Conflict of Interest Management

This year, we reviewed our DSO governance arrangements across SPEN confirming that functional separation remains the right model, while identifying opportunities to strengthen its operation. This led to an expanded DNO:DSO Operating Framework, with two new Codes of Practice for Network Planning and Development and Network Operations, giving clearer role separation and decision pathways. This builds on our approach to conflict management, including the standalone Conflict of Interest (COI) Management plan introduced last year, which we believe places us at the forefront of DSO governance.

Through close collaboration with over 100 tRESP meetings with NESO and stakeholders. tRESP outputs are now within 1% of our DFES and LCT forecasts, including our Clean Power (CP) 2030 Gate 2 outlook. This level of alignment is not seen in all DSOs and reflects the strength of our forecasting and our close collaboration with NESO, including detailed geospatial review of the pathways and planning assumptions with testing, review, and feedback throughout tRESP development.

We improved the impartiality and robustness of our options assessment by improving our ENZ platform to support more data-driven and consistent evaluation of network and non-network solutions. Oversight has been enhanced through a more targeted assurance approach, combining internal governance with focused external challenge via a new DSO Advisory Group. Together, these changes provide a clearer and more robust framework for decision-making, options assessment, and the management of conflicts of interest in process.

4.1 – Assessment of Network Options

Criteria	Key Evidence
4.1.1 – Clear and accessible evaluation methodology	**New –** Improved accessibility with feature pages and dashboards on the ODP for DFES and DNOA, added the LTDS in CIM, and a Future Networks theme to collate all planning datasets. **Existing –** Options assessment documents are on our website, including the Decision Making Framework (DMF), NDP, DNOA, LTDS, and DFES. **Existing –** Strategic Optimisers inform LAs, regional bodies, and heat, transport, and industrial stakeholders of planning decisions.
4.1.2 – Consistent evaluation methodology that ensures the solution is economical and efficient over the long-term	**New –** Incorporated the tRESP Pathways and CPAs into our ENZ Platform. **Expanded –** Strengthened the methodology with our upgraded ENZ platform, using a complete network model, granular forecasting, and mixed-integer linear optimisation for more consistent, data-led, and impartial options assessment. **Existing –** Apply a consistent methodology within our governance framework, with the DMF and DNO:DSO Operating Framework supported by the Ofgem-informed CBA and CEM. **Existing –** Ensure long-term economic efficiency by using whole-life value assessment, and by identifying the combination, sequence, and timing of interventions that minimise NPV over time, including where flexibility or energy efficiency can endure, defer reinforcement or complement it.
4.1.3 – Cross-sector and vector engagement and consideration of whole system options	**New –** Undertook extensive engagement with NESO and stakeholders around tRESP, including over 100 meetings, to reflect local and regional network and stakeholder needs. We worked with NESO to ensure its planning assumptions reflected our customers' behaviour and regional factors, supporting more economic network planning and timely capacity delivery. **Expanded –** Extensive engagement with 40 LAs, 12 regional bodies and transport bodies, industrial clusters, and investment zones, providing cross-sector evidence for our options assessment. **Expanded –** Active engagement across the electricity sector with DNOs, IDNOs and transmission operators, to align assumptions, incorporate regional and cross-boundary developments into options assessment, and consider more efficient whole-system solutions. **Expanded –** Strengthened coordination with neighbouring networks and other operators, to align assumptions, identify joint solutions, and support more efficient cross-boundary options assessment. **Existing –** Cross-vector engagement gas, including with GDNs and other sector bodies, ensuring our assessment of network needs reflects wider energy system developments and opportunities.

4.1.1 – Making our network needs evaluation methodology clearly defined and accessible to DSO Stakeholders

Articulating our options assessment process: Our network evaluation methodology is clearly defined and accessible to stakeholders through a suite of published process and planning documents. Our new standalone Planning DMF explains how we identify and impartially assess viable options to meet network needs, while our DNO:DSO Operating Framework sets out the responsibilities of DNO and DSO teams. This is supported by our newly developed Code of Practice Network Planning and Development, which provides further details on how these responsibilities are delineated. The supporting evidence is published via: DFES provides long-term demand and generation forecasts; LTDS provides short-term technical network and development data; NDP sets out medium-term headroom and planned interventions; and DNOA publishes location-specific options assessment outcomes, including the identified constraint, flexibility tendering details, and chosen intervention, supported by Engineering Justification Papers. These help stakeholders understand how decisions are made and the evidence behind them. 4.1.2 includes a step-by-step case study to illustrate the process.

4.1.1 – Making our network needs evaluation methodology clearly defined and accessible to DSO Stakeholders *continued*

Continuing to improve accessibility and transparency: We have improved accessibility and transparency by making this information easier to find and use. Planning information is more accessible through our ODP, with the DFES, NDP, LTDS, and DNOA datasets now grouped in a Future Networks theme. We added interactive feature pages for DFES and DNOA to turn raw datasets into simple visualisations, made the LTDS available in CIM, and published six new DNOAs (three each for SPD and SPM), for a total of 49 (29 for SPD and 20 for SPM). These give stakeholders clearer visibility of constraints, solutions considered, and decision rationale, with our Policies, Procedures, and Specifications page, which provides frequently requested specifications and standards. Additionally, all LAs, regional bodies, transport, and industrial cluster stakeholders are informed of the latest planning publications and developments by our Strategic Optimisers, keeping them part of the planning process – as explored in 4.1.3.

4.1.2 – Utilising an evaluation methodology that selects network options, which are economical and efficient over the long-term, and recognises the value of energy efficiency and flexibility

A consistent methodology within a clearly governed framework: We continue to apply a consistent and clearly governed methodology to options assessment through our new Planning DMF and DNO:DSO Operating Framework. The DMF follows a five-stage decision-making process, where the Stage three Options Assessment Process, assesses all network needs and credible solutions against the same core criteria shown below, and is supported by industry-standard approaches including Ofgem's CBA and the ENA CEM. The solutions assessed include flexibility, energy efficiency, smart network interventions, network reconfiguration, and conventional reinforcement, considered individually and in combination to identify the optimal solution. This year, we commissioned Threepwood, a power engineering consultancy, to independently review our options assessment process, including whether it contained any bias. The review is underway, and results are due later in 2026.

DMF Stage 3: Options Assessment – The three criteria options are assessed against

Technical

- **Customer needs** – Can it provide the required capacity
- **Technical requirements** – Technically feasible and doesn't introduce other issues

Cost

- **Whole life cost** – Cost benefit considering CAPEX and OPEX
- **Environmental impact** – Losses, noise, visual impact, and carbon impact

Other

- **Timing/delivery** – Can the solution be delivered in time
- **Whole system** – Transmission/distribution and cross vector interactions

Using advanced modelling to strengthen consistency and impartiality: Our ENZ planning platform enables us to identify the most robust and cost-effective solutions for stakeholders, improving value for money, reducing bills, and supporting timely delivery of capacity. The ENZ's combination of components makes it market leading: NAVI, our industry-leading, self-healing digital twin, provides a powerful connectivity model and, from this year, updates the ENZ daily with real-time substation, network, LV monitor, and smart meter data; ENZ then uses network modelling and half-hourly simulations to identify emerging constraints; and its mixed-integer linear optimiser impartially tests intervention combinations and timings to identify the most economically efficient long-term pathway. This year, we further strengthened ENZ by incorporating NESO's tRESP pathways and Consistent Planning Assumptions (CPAs), improving alignment with whole-system scenarios and the national planning framework. Together, these enhancements enable earlier identification of constraints and faster and more consistent updates to intervention plans.

Ensuring long-term economic efficiency through whole-life assessment and least-cost pathway optimisation: We continue to ensure the preferred solution is economical and efficient over the long-term by assessing all credible options, rather than defaulting to the lowest upfront-cost intervention. This is strengthened by ENZ, which uses data-led modelling and optimisation to identify the most economic combination, sequence, and timing of interventions over the long-term and based on whole-life cost, deliverability, and NPV.

Our methodology treats flexibility not only as an alternative to reinforcement but as a way to manage uncertainty, defer higher-cost intervention, or complement reinforcement within the optimal pathway. Through CEM, we compare flexibility and non-flexibility options on a common basis, including the NPV of the alternative solution, while ENZ tests intervention combinations and timings to identify the lowest-cost pathway over time. We also assess energy efficiency where it can reduce demand growth, peak loading, and wider system costs. This helps us identify the most economical and efficient long-term solution while recognising the option value of flexibility and energy efficiency, as shown in the example below.

Stage 1: Forecasting	DFES 2026 forecasts, incorporating NESO's tRESP pathways and CPAs, fed into ENZ show that rising demand and LCT uptake will keep increasing pressure on the Castle Primary group, which reaches capacity limits in RIIO-ED2.
Stage 2: Network Assessment	ENZ shows that Castle Primary has already reached capacity, with no headroom on its 15/21MVA 33/11kV primary transformers and limited thermal capacity on the associated 33kV circuits, creating a near-term constraint that worsens as LCT growth increases.
Stage 3: Options Assessment	We then evaluate all credible options. At Castle, the preferred solution is to procure flexibility services, which is the most economical and efficient way to manage demand growth and uncertainty into RIIO-ED3 (ED3).
Stage 4: Flexibility Tendering	In the short-term, we utilise flexibility through our month-ahead model to manage the potential thermal constraint due to LCT growth identified from DFES forecasts.
Stage 5: Intervention Decision	Flexibility will manage immediate LCT-driven capacity needs in the interim, while enduring capacity options are developed for the ED3 period, deferring a high-cost intervention while demand growth and timing remain uncertain.

4.1.3 – Cross-sector and vector engagement and consideration of whole system options

Our proactive engagement with and support for Local Authorities: We maintain collaborative relationships with network users across our licence areas, primarily through quarterly engagement with the 40 LAs in our license areas, and engagements with 12 regional bodies. Through this, we support LAs' energy planning, including LHEES and LAEPs where applicable, and LCT optioneering through our award-winning LANIT platform. This year, we directly supported 11 LAs' decarbonisation plans, with six in SPD and five in SPM.

Our extensive tRESP engagement: By aligning regional and local energy needs with national planning, our work with NESO on tRESP has helped ensure local, regional, and devolved government stakeholders' plans are reflected in the assumptions that will shape future network development. We supported NESO's development of their tRESP outputs, with multiple rounds of detailed feedback, over 100 meetings with NESO and stakeholders, providing our demand, generation, and LCT forecasting, and LA, devolved government, and major stakeholder projects via our RSP. Our early geospatial analysis, detailed feedback, and targeted information requests helped achieve near-perfect alignment between tRESP outputs and our DFES, EV, and heat pump forecasts, within 1%, while generation forecasts match our view of the Gate 2 pipeline. These shared pathways now underpin our ED3 load plan, enabling around 2.5 million LCTs, over 35% demand growth, and more than 5.5 GW of new generation, and we will continue working with tRESP to ensure high-certainty strategic needs are reflected in our baseline ED3 plan. The CPAs introduced a standardised national framework, with only minor refinements since the draft stage and no material impact expected on ED3 planning.

Case study: LANIT – our award-winning LCT optioneering tool

In December 2025, LANIT won the Best Innovation: Software and Services award at the Scottish Green Energy Awards for helping LAs and regional bodies plan for a decarbonised future, and was extended to more transport organisations and regional bodies. Built on our digital twin, NAVI, it lets users assess potential LCT sites by modelling grid impacts and likely costs, supporting projects such as EV charging, heat pumps, and solar on an intuitive map interface. This year, LANIT has been used to assist 21 LAs with optioneering assessments to deliver 2,579 optioneering assessments, including the Ayrshire CoRE project, where we assessed 300 prospective electric vehicle charging sites and 74 proposed heat pump sites giving early visibility of costs and timescales before formal connection applications.

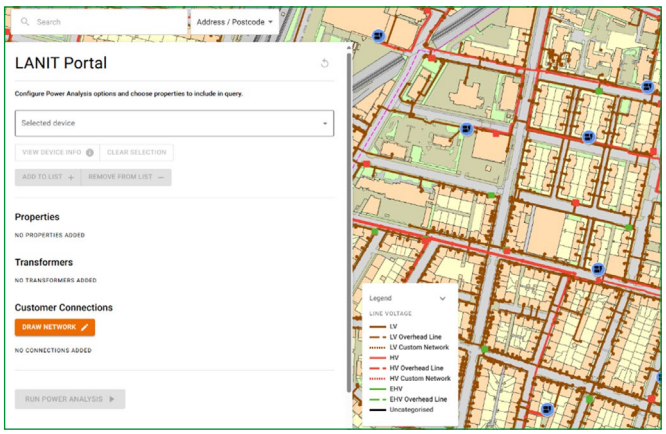
Developing whole system solutions with other network companies: We assess wider whole-system options through coordination with transmission owners, neighbouring networks, and IDNOs, so that identified needs are addressed at the lowest cost across the wider system, not just within distribution. This year, we strengthened coordination with neighbouring networks, including through:

- Working with NGET on the Mersey Ring Upgrade Programme to expand North-South transmission capacity, enabling greater renewable power flows from Scotland and supporting decarbonisation-led demand growth. To support rising electricity demand, economic growth, and LCT uptake driving capacity constraints in Mid-Wales, we are working with NGED, NGET, IDNOs, NESO, the Welsh Government, RenewableUK Cymru, and DESNZ to identify the lowest-cost, multi-voltage, and whole-system solutions. Through fortnightly coordination with NGED and NGET, shared SharePoint workspaces, and joint engagement with government stakeholders, we have developed coordinated transmission-distribution infrastructure options for the PSNC project, which NGET has now submitted to NESO in the TCSNP2 refresh. This whole-system approach is groundbreaking for the extent of stakeholders involved in collaborative infrastructure planning in Wales, and supports decarbonisation and generation growth aligned with CP2030.
- Coordinating with NESO and NGET to support their outage management using distribution Flexibility, as explored in 3.2.3.
- Coordinating with SPT to address network needs identified through our DFES and tRESP, including whole-system options assessment at the T/D boundary to manage capacity constraints and support renewable growth and decarbonisation demand.

Collaborating with sectors: We work with various network users, including gas networks, three industrial clusters, three investment zones, and three transport bodies, working to both understand their needs and ensure our planning supports their future developments. Below is a selection of our ongoing projects:

- Gas networks: In SPD, we are working with a solar PV developer and a gas network operator who are seeking connections in the same area of the network. Rather than defaulting to separate network connections, we are exploring dual-use connections, with coordinated planning and flexibility-led options, to improve asset utilisation and reduce connection and reinforcement costs. This is improving cross-vector visibility, supporting more proportionate investment decisions, and whole-system, alternatives-first planning.
- Transport bodies: Through engagement with Transport Scotland and Heriot-Watt University, we updated our forecasts and network assessments on future decarbonised transport. We also work with the Office for Zero Emission Vehicles and National Highways to identify network solutions for ultra-rapid charging at motorway services and update our wider network planning for SPD and SPM.
- Industrial bodies: In SPD, we are working with Forth Green Freeport to address a capacity shortfall at Rosyth that could require long and costly distribution reinforcement. By working with SPT on a whole-system basis, we identified a more cost-effective non-build option using transmission-side flexibility and load management, which has been supported by NESO through CP2030. We are also engaging across the wider Freeport, including with NESO at Leith, to identify future needs early and support them through whole-system solutions in ED3, enabling growth at lower system cost. This approach has been informed by our newly launched NZIP innovation project, which applies the NEWID whole-energy-system methodology to improve industrial decarbonisation forecasting and provide early inputs to our ED3 plan.

Extensive cross-sector engagement to inform our options assessment: Our options assessment has a strong cross-sector evidence base informed by structured engagement set out above. Through the RSP, these inputs feed into DFES, LTDS, and the NDP, shaping the needs, modelling and forecasting assumptions, and options we assess. LANIT complements this by providing early visibility of likely constraints, reinforcement needs, and timescales for LCT projects.



4.2 – Management of conflicts of interest

Criteria	Key Evidence
4.2.1 – Further formalising the relationship between our DNO and DSO	New – Updated DNO:DSO Operating Framework for our potential integration with SP ENW. New – Reinforced the framework with supporting Codes of Practice for Network Planning and Development and Network Operations to support existing governance frameworks.
4.2.2 – Strengthened proportionate measures to identify and address actual and perceived conflicts of interest	New – Created DSO Advisory Group for independent oversight and integrated into governance structure, providing a focused and proactive external challenge on DSO activities and conflict management. New – Managed perceived conflicts in Dynamic Voltage Control by identifying potential licence and market conflicts early, drawing on CLASS best practice, legal advice, and awareness of voltage, retail, and REMIT obligations through governance and DSO Advisory Group oversight. Expanded – Robust governance framework mitigating conflicts of interest, with the DNO:DSO Operating Framework and supporting documents, formalising the relationship and functional separation within decision-making. Governance structures were refreshed in preparation for our integration with SP ENW. Expanded – Standalone COI Management Plan was refreshed this year, providing a clear, operational approach to managing actual and perceived conflicts, with ongoing internal and external scrutiny. Only DSO with a standalone plan, providing dedicated focus and assurance. Existing – Executive accountability and board-level visibility embedded in the governance model, ensuring DSO decisions are subject to clear senior ownership and oversight.
4.2.3 – Using stakeholder engagement to develop buy-in to our approach	Existing – Used extensive stakeholder engagement and previous Independent Net Zero Advisory Council (INZAC) input to develop our Conflict of Interest Mitigation Plan and our DNO:DSO Operating framework.
4.2.4 – Availability of outcomes of investment decisions	Expanded – All investment decisions are publicly available, with full dataset access on our website and ODP, for our NDP, DNOA, and LTDS, with expanded data and feature pages added to the ODP.
4.2.5 – Applying best practices, and seeking and sharing insights with other DSOs to update our approach in line with industry developments	New – Confirmed our DSO governance and compared it to industry models, during the review for the potential SPEN SP ENW integration. Expanded – Regular engagements with Iberdrola's global team and Spanish DSO counterparts to learn from international best practices. Expanded – Learning from and sharing insights on DSO governance and COI management with Spanish counterparts, ENA DSO Directors forum, and Elexon Flexibility working groups.

4.2.1 – Further formalising the relationship between our DNO and DSO

We have an established framework for managing conflicts of interest through clear role separation, transparent decision-making, and formal governance. Our DNO:DSO Operating Framework outlines how DNO and DSO teams collaborate and how decision-making is separated. This year, in anticipation of our integration with SP ENW, we reviewed and updated our DNO:DSO governance with an independent partner. From this, we establish a new Control Room and DSO directorate, further separating decision-making from our DNO, and ensuring that the Control Room and DSO evolve together to support dynamic network operation. We introduced Codes of Practice for Network Planning and Development and Network Operations, respectively, that define the rules, behaviours, timescales for decisions, and controls governing DNO:DSO interactions and acting as service level agreement, to strengthen the identification, management, and escalation of actual and perceived conflicts of interest. Finally, we formed the DSO Advisory Group, a new independent advisory group that takes over the responsibilities of the INZAC DSO Subset, and incorporated it into our governance structures, as explored in 4.2.2.

4.2.2 – Strengthened proportionate measures to identify and address actual and perceived conflicts of interest

Robust framework for mitigating conflicts of interest: Our DNO:DSO Operating Framework defines roles, responsibilities, and decision-making authority, while our new Codes of Practice further clarifies the separation of DNO and DSO roles in decision making. As set out in 4.1.1, this embeds separation into options assessment and decision-making, mitigating conflicts of interest by ensuring viable options are assessed objectively and in customers' best interests. This year, we commissioned Threepwood to review our five-stage options assessment, including whether there is any bias in the process.

This is supported by our standalone COI Management Plan, which sets out how actual and perceived conflicts are identified, assessed, recorded, mitigated, and escalated through formal governance, including DSO Advisory Group review. This year, we expanded the Plan beyond internal business interests to consider wider industry interests, including where distribution decisions may affect the wider electrical system or wider industry processes, strengthening whole-systems oversight. Together with the objective options assessment approach described in 4.1.1, this helps ensure decisions are impartial and focused on the best outcome for customers.

Case study: Evidence of our conflict of interest approach in practice

Our DSO team has advanced the strategic development, design, and delivery of Dynamic Voltage Control for ED2 and in preparation for enhanced ED3 requirements, and is an example of how we manage perceived conflicts of interest during process. Early on, we drew on the CLASS project's best practice, recognised potential conflicts of interest and licence implications, should we deliver market services under the licence derogation. We took legal advice while strengthening regulatory awareness across voltage and retail obligations, including REMIT, supported by presentations to INZAC DSO Subset.

Mitigating conflicts of interest in process: We mitigate conflicts of interest within the decision-making process, rather than resolving them later. Potential conflicts can be raised internally or by external stakeholders at any stage and are assessed to determine whether they are actual or perceived. Where a conflict is identified, the mitigation is applied immediately, supported by formal assessment, recording in the COI Register, review by the DSO Governance Lead, and approval by a designated DSO Lead. Conflicts then remain under active review through our bi-monthly DSO Steering Committee, where they are a standing agenda item, so mitigations can be strengthened or escalated as circumstances change.

Ensuring board and executive-level accountability and visibility of DSO decisions: Executive accountability for DSO decisions is built into our governance through clear approval routes, senior challenge, and direct oversight by the CEO, directors, and the board. Under the DMF, interventions are technically reviewed by the System Review Group and DSO team before financial approval. Schemes up to £1 million are approved by the relevant Licence Director, while larger schemes go to the Investment Review Group, including the CEO and directors. Board-level oversight is reinforced through the Head of DSO's direct reporting line to the CEO and twice-yearly board briefings on DSO activities, governance, and decision-making.

Ensuring independent oversight on all conflicts of interest: In 2026, we formed the DSO Advisory Group to provide focused oversight of DSO matters, taking over the INZAC DSO Subset's previous role and operating separately with a new chair, but with shared membership providing continuity. INZAC, now refreshed as our Independent Stakeholder Group, remains our independent panel of 15 external experts, providing challenge, specialist insight, and oversight across our transmission and distribution activities. The DSO Advisory Group supports conflict management by overseeing DSO activities, identifying potential conflicts during the process, and reviewing proposed mitigations, ensuring independent oversight both before and after conflicts are recognised.

4.2.3 – Using stakeholder engagement to develop buy-in to our approach

Last year, we developed our COI Management Plan through consultation with stakeholders, combining detailed input from our INZAC DSO Subset, with a public consultation, which led to the introduction of independent oversight and 95% stakeholder support for our approach. This year, after review by the INZAC DSO Subset, we updated the Plan to strengthen alignment with proportionality, transparency, accountability, and fairness. Additionally, stakeholder and external input informed our review of governance arrangements, including the DNO:DSO Operating Framework, as part of the SPEN and SP ENW governance review ahead of potential integration. We have also engaged with external partners, Iberdrola's global team, and Spanish DSO counterparts to understand how other operators manage conflicts of interest and how to strengthen our approach. We also used the Flexibility Summit to identify wider conflicts in live market design by bringing participants together to work through issues and potential conflicts in flexibility market development.

4.2.4 – Availability of outcomes of investment decisions

We publish investment decisions through the planning documents and datasets referenced in 4.1.1, including our NDP, LTDS, DFES, and DNOAs (three each for SPD and SPM), with supporting data available through our ODP. This year, we published six new DNOAs (three each for SPD and SPM), bringing the total to 49 (29 for SPD and 20 for SPM), supported by Engineering Justification Papers and a new feature page on the ODP providing clearer visibility of the constraints identified, options considered, and interventions selected. We publish related planning and procurement information through our website, ODP, and flexibility reporting, making decision outcomes available through multiple accessible routes.

4.2.5 – Applying best practices, and seeking and sharing insights with other DSOs to update our approach in line with industry developments

We have continued to strengthen our governance arrangements and conflict management by learning from wider industry and international practice. As part of our DSO governance review for the potential integration of SPEN and SP ENW, we worked with an external partner to examine how other DSOs separate DSO and DNO activities. We also engage regularly with Iberdrola's global team and Spanish DSO counterparts to understand how other markets test governance and conflicts of interest, including through different regulatory sandbox approaches. We complemented this with wider local industry engagement through Elexon flexibility working groups and the ENA DSO Directors forum, using these forums to explore potential industry-wide conflicts such as flexibility market design and asset visibility. This ensures our model remains appropriate, identifies areas where governance and conflict management could be strengthened, and opens up ideas that could be taken forward in the GB.

5. DER Dispatch and Decision Making

This year, we pursued a three-part strategy to strengthen DER dispatch and curtailment: improving visibility of customer assets to run the network more effectively and unlock flexibility opportunities; establishing a clearer, more transparent curtailment approach; and strengthening operational and governance links with NESO to better coordinate transmission and distribution decisions. We continue to lead the deployment of LV monitors, installing 2,205 LV monitors in SPD and 1,563 in SPM, for a total of 3,768, bringing the total to 11,768, which is 76.5% of our updated ED2 target of 15,000. This increased customer coverage from 46% to 51%, and smart meter saturation rose from 54% to 62%. We also improved DER data quality, increasing ECR completeness from 85% to 99.99% and with validity increasing to 86.4% from 85%, reflecting the significant increase in DER connecting and being added to the ECR. We introduced the new Flexibility Assets dataset and began integrating it into Netview, while updating ENZ with live NAVI data to better support planning, flexibility procurement, and dispatch decisions. In response to Panel feedback, we introduced a curtailment strategy in our Operations DMF, improved collaboration with FSPs through our Flex Engagement Strategy, and strengthened coordination with NESO by integrating SPD and SPT PowerOn SCADA into a single control platform, giving SPD direct access to the ICCP link with NESO. We also completed the centralised CMZ platform, improved Control Room visibility of ANM-connected DER sites in SPD, and completed six CMZs in SPD and seven in SPM.

Criteria	Key Evidence
5.1.1 – Implementing a comprehensive and robust visibility of DER characteristics and data parameters and its use to inform effective and coordinated dispatch instructions	New – Introduced the Flexibility Asset dataset to capture all FSP assets registered on our flexibility tendering platform, extending visibility of DER below 1MW. This dataset is being integrated into our network model, enabling data-led decision-making for dispatch of flexibility and network operations. Expanded – Installed 2,205 LV monitors in SPD and 1,563 in SPM, for a total of 3,768, for improved network visibility and assessment of flexibility needs, and now covering 51% of total customers. Expanded – ECR completeness increased from 85% to 99.99%, with 86.4% validity. Expanded – Completed project utilising smart meter data to recognise unregistered LCTs, unlocking new abilities to monitor domestic LCTs. Expanded – Deepened integration of DER into operations, including StormFlex, Control Room visibility of DER via centralised CMZs, and Flexibility Asset dataset integration into NAVI. Existing – Continued to install real-time monitors at all DER sites with 1MW or more capacity, and captured in the ECR.
5.1.2 – Implementing a clear and transparent decision-making framework for when DER are instructed to dispatch in real-time	New – Updated our DMF to separate the Planning activities and Operational activities. Included in the DMF – Operational our curtailment approach in response to Panel feedback, clarifying how curtailment is triggered, prioritised and communicated. Expanded – Continued to apply the dispatch DMF, now tested through a full year of use and we have implemented the ENA primacy rules, and are in the process of implementing the Elexon Primacy Rules. Existing – Continued to dispatch planned flexibility to managed reinforcement and planned outages, and utilise flexibility to mitigate unplanned outages.
5.1.3 – Operating an efficient, scalable dispatch instruction infrastructure, with clear definitions and transparent rules	New – Finalised ElectronConnect as our new flexibility dispatch platform through a competitive tender. We have worked closely with Electron to enhance the platform, which now provides automated dispatch with clear contractual rules and avoids “hard-coded” operational capabilities, while enabling future expansion, and implemented the Common Dispatch API to further standardise dispatch instructions. New – Deployed six new CMZs in SPD and seven in SPM, and finalised the designs and procurement for the deployment of nine new CMZs in 2026, compared to zero deployed in 2024/25. Expanded – Increased scalable curtailment capability by implementing CMZ centralisation, strengthening ANM measurement and control at constrained DER sites to support more consistent, automated curtailment.
5.1.4 – Implementing DSO-GB System Operator communication channels	Expanded – SPD now has direct ICCP access to NESO, enabled by SPD and SPT’s integrated single platform PowerOn SCADA control systems. Expanded – Progressed the SPM ICCP link with NESO. An interim tactical solution was proposed, accelerating deployment to January 2026, but was not accepted by NESO. The enduring solution will be operational by Q3 2026. Existing – Continue sharing operational information with NESO via Week 24 and 52, Regular Reporting Pack, and tRESP engagements.
5.1.5 – Working to increase DER participation in GB System Operator markets and implementing optimised whole system coordination of DER to resolve conflicts of service between SO and DSO	New – Undertaking a study of the relationship between distribution flexibility and the impact on the network, to advance industry wide support for transmission constraints using distribution flexibility. Expanded – Progressed whole-system ambition through joint initiatives including Demand Flexibility Services, Megawatt Dispatch, LCM and Demand for Constraints. Existing – Supported DER access to NESO markets with non-exclusivity clauses and stacking provisions in flexibility agreements.

5.1.1 – Implementing a comprehensive and robust visibility of DER characteristics and data parameters, and its use to inform effective and coordinated dispatch instructions

This year, we enhanced both the scope of our visibility of DER characteristics and how this data is utilised in planning and operational decision-making. In response to last year's panel feedback, we have focused not only on gathering more DER and network data, but also on integrating that data more directly into the systems used to evaluate network needs, acquire flexibility, and support effective, coordinated dispatch instructions.

Expanding visibility of DER characteristics and network data:
We have strengthened DER visibility as part of a more DSO-led approach to running the network, making a wider range of customer assets and behaviours visible so flexibility can be valued, used, and dispatched more effectively. This enables us to more effectively utilise DER, understand their behaviour and needs, and take a data first approach to network management. We have done this by improving the data captured through our connection and flexibility processes, expanding the devices that provide real-time network visibility, and using our systems and analytics to improve data quality and close remaining gaps. Together, this gives us a broader, more current, and more robust view of DER characteristics and network conditions to inform planning, flexibility assessment, and coordinated dispatch.

We first strengthen visibility through the processes that capture DER and flexibility data and feed it into our operational systems. For new G99 connections, we capture DER characteristics through the connections process and feed them into the ECR and the Control Room operating model, so network operations reflect the current connected DER base. This year, we also introduced the Flexibility Assets dataset, which captures FSP assets registered on ElectronConnect, their location, and their export and import capacity from our flexibility tendering platform, extending visibility of smaller flexibility assets below 1MW. In parallel, ECR completeness increased from 85% to 99.99%, with data validity increasing from 85% to 86.4%, with the small increase due to the significant number of new DER assets being added to our network this year, as explored in 3.2.2. These measures have strengthened the quality of the DER data used in operational decision-making.

We then expand visibility through the devices that provide real-time network and DER data. We continue to install real-time monitors at DER sites connecting at 132kV, 33kV, or with 1MW or more capacity, giving our Control Room visibility of DER operations. This year, we also completed the Centralised CMZ system and connected it to the SPD Control Room, providing real-time visibility of DER on ANM connections. Alongside this, we expanded visibility across the wider network by installing 2,205 LV monitors in SPD and 1,563 in SPM, for a total of 3,768, taking the total to 11,768, up from 6,768 last year and now covering 51% of total customers, with the smaller increase due to the more complex expansion into rural areas. Smart meter saturation across our licence areas also rose from 54% to 62%. This year, we further improved how NAVI uses smart meter data by moving from weekly to nightly updates, resolving many LV visibility constraints and giving us far closer to real-time visibility of the network, complemented by half-hourly LV monitor updates.

Finally, we use network analytics and machine learning to enhance the available datasets through inference where there is sufficient customer data to do so. NAVI supports both planning and operational use by combining DER data, monitor data, and wider network information into a single view of the network from LV to EHV. This year, we used NAVI not only to improve visibility of connected DER, but also to identify previously unregistered domestic LCTs. In a BAU-funded initiative, we used the consumption data from 2,500 disaggregated smart meters, showing that NAVI can identify unregistered household EVs and heat pumps with a high degree of accuracy. We are now exploring how to secure wider and ongoing access to disaggregated smart meters consumption data, and how to identify additional LCT types as we expand our database of consumption and generation patterns. This helps us understand a broader range of customer technologies and behaviours, including assets that have traditionally been less visible to network operators.

Deeper integration of DER visibility into operational systems:
This year, we concentrated on addressing the panel's feedback by enhancing both the quality and coverage of DER and flexibility asset data, and by integrating that data more directly into real-time operational decision-making. We improved visibility across the systems and teams responsible for identifying constraints, evaluating options, and supporting dispatch, so DER data is more accessible and more practical to use.

We updated the ENZ, our internal tool for assessing network constraints and flexibility requirements, to better utilise network data and improve the identification of flexibility needs. This helps us determine where flexibility is needed, the scale of the requirement, and the timing of interventions more accurately. We also began integrating the Flexibility Assets dataset into Netview, NAVI's near-real-time network visualisation, enabling operational teams to view registered flexibility assets alongside current network conditions on a map. This provides district teams, the Network Support Room, and the Flexibility Team with a clearer view of where flexibility is available and how it can be utilised to address constraints. This stronger integration is also evident in operational practice. The Flexibility Team works with the Control Room to translate operational network needs into flexibility requirements, and the upcoming API link between ENZ and ElectronConnect will enable flexibility requirements to be updated as constraints are identified. Consequently, this means improved DER visibility increasingly informs operational decisions, rather than remaining as separate planning information.

Our BAU StormFlex product clearly illustrates this in practice. We expanded StormFlex from one DER site with 20 MW to four DER sites with 201 MW of contracted capacity. As part of our storm response strategy, the Network Support Room uses NAVI to identify opportunities to energise the network from DER sites, and the Flexibility Team then issues dispatch instructions to those DER sites to restore customers more quickly. This demonstrates how DER visibility is now more directly linked to operational action and coordinated dispatch.

5.1.2 – Implementing a clear and transparent decision-making framework for when DER are instructed to dispatch in real-time

Last year, we established a clear and transparent dispatch decision-making framework through our DNO:DSO Operating Framework and DMF. In response to the Panel's feedback on a lack of a curtailment strategy, we have introduced separate Planning and Operations DMFs, and supporting Codes of Practice for each. The DNO:DSO Operating Framework formalises the separation between DNO and DSO decision-making in flexibility dispatch, while Stage 4 and 5 of the Planning DMF guide when flexibility is used in options assessment. The Operations DMF then clearly details how and when we dispatch and curtail DER, explaining how curtailment and flexibility dispatch is triggered, prioritised, and communicated to DER on flexible connections , and the Code of Practice Network Operations details how curtailment and dispatch decision making is split between DNO and DSO. This will ensure that our approach to implementing curtailment is consistent and transparent to stakeholders. To make this framework clearer for all participants, during our extensive engagements with FSPs, outlined in 3.1.3, we have aided FSPs in understanding the dispatch process to ensure it is clear to FSPs with varying levels of technical knowledge.

5.1.3 – Operating an efficient, scalable dispatch instruction infrastructure, with clear definitions and transparent rules

This year, we improved our dispatch infrastructure through a competitive tender process, commissioned a new flexibility tendering and dispatch platform, ElectronConnect, as further described in 3.2.1, and expanded our curtailment infrastructure through our CMZs, delivering a fully automated dispatch and curtailment infrastructure.

Operating an efficient, scalable, and automated dispatch infrastructure: Our work with ElectronConnect has enhanced the way flexibility dispatch instructions are issued. ElectronConnect offers an efficient, scalable dispatch platform capable of supporting continued market growth and adapting to changing market structures, primacy rules, and regulatory requirements without hard-coding capabilities. It automatically generates dispatch schedules from bid results and ENZ-identified requirements, sends dispatch instructions to FSPs via API, and produces settlement reports for the Flexibility Performance team to review. This improves efficiency through real-time processing, reduces data entry errors, and standardises flexibility procedures. We further strengthened this process this year by adopting the Common Dispatch API, which standardises dispatch instructions via an industry-standard API, enhancing interoperability for DER across DSOs.

Expanding our curtailment dispatch system: We continue to manage the dispatch of curtailment instructions for flexible connections through a combination of infrastructure technologies. These are split between our LMS in SPD and LoMS in SPM, which are existing technologies that are used to manage demand, generation, and storage customers where transmission constraints exist, and this year, have enabled contracted connections for six DER in SPD, totalling 174 MW, ahead of reinforcement. Our newer ANM-type schemes, CMZs, enabled contracted connections for three DERs (72 MW) in SPD and four (48 MW) in SPM. These schemes allow us to implement new DER connections ahead of both distribution network constraints and transmission network constraints via Technical Limits solutions at the T/D boundary.

This year, we completed deployment of the centralised CMZ system, with SPD and SPM CMZs now hosted on a single control server in each licence area. In SPD, the CMZ system is now connected directly to the Control Room through the ICCP link, providing real-time visibility of ANM-connected DER sites and enabling NESO visibility through the SPD-NESO ICCP link if required. The centralised system also allows faster, lower-cost deployment by reducing on-site interventions and control points compared to the non-centralised system, and by making it easier to update CMZ operation in response to market rules or network capacity changes. We also introduced several upgrades, including fully automated seasonal settings to adjust circuit ratings based on seasonal weather conditions, and updated Real-Time Automation Controller logic, enabling more precise automated decisions on when and how much DER is constrained.

Our CMZ scalable solution has enabled us to deploy six CMZs in SPD and seven in SPM this year, which are in operation. A further six CMZs are to be delivered in SPD and three in SPM by the end of 2026. Additionally, this year, for the remaining 12 CMZs to be deployed in ED2, we completed testing the connection to the Centralised platform and are making progress with the bulk installation of communication equipment and measuring points for those in SPD. This will ensure we are able to continue the timely deployment of these systems.

5.1.4 – Expanding DSO-GB System Operator communication channels

We continue to share operational information with NESO through standard mechanisms, including Week 24 and 52, the Regular Reporting Pack, and tRESP engagements. We continue to progress with ICCP development, with the expectation of full ICCP link established in SPM in 2026.

Utilising the ICCP links for NESO communication: We have now fully integrated the SPD and SPT PowerOn SCADA control system, providing SPD with direct access to the NESO ICCP link. This replaces the previous setup, where SPD data was routed through SPT's SCADA system. NESO confirms this still meets their requirements, as it delivers the same volume and frequency of data as a standalone ICCP link, and thus they do not want a separate link. Via the ICCP link we continue to share data from DER monitors at large DER sites of 1MW or more, including plant status, analogue values, wind speed, available power, plant positions, and GSP-level analogue data. Late last year, NESO confirmed it was ready to progress the SPM ICCP link. In December, we proposed an interim solution to enable data transfer from January while an enduring solution was implemented. NESO declined this and opted to proceed directly with the enduring solution, which is due to be completed by the end of Q3 2026.

5.1.5 Working to increase DER participation in GB System Operator markets, and optimising whole system coordination with NESO

Designing DER contracts to facilitate DER access to GB System Operator markets: We support DER access to NESO markets by ensuring our flexibility contracts contain no exclusivity clauses and include stacking provisions, so participation in our markets does not prevent access to NESO markets. However, contract design alone is not enough to bring smaller DER into the market. Through our stakeholder engagement programme, we provide the practical support needed to help smaller providers navigate market complexity and access both distribution and NESO markets. This is a key DSO role and an important value-add for customers, because it helps make smaller assets visible and valuable to the system, broadens participation in flexibility markets, and increases the DER available to support both distribution and transmission needs. As explored in 3.2.3, we are also developing initiatives with NESO to improve DER access to their markets, including Demand Flexibility Services, Megawatt Dispatch, Local Constraint Markets, and Demand for Constraints. We believe DSOs have a key role in helping NESO access consumer-led and DER flexibility through this combination of market design, engagement, and local coordination.

Optimising whole system coordination with NESO to resolve DER conflicts of services: We have implemented the ENA primacy rules, and are in the process of implementing Elexon's primacy rules, ensuring we can resolve conflicting instructions to DER from ourselves and NESO and support transparent whole-system optimisation across transmission and distribution. This matters to customers because it allows flexibility and DER to be used more efficiently across both networks without conflicting signals or unnecessary barriers to participation. We are also helping shape the wider industry approach by studying how flexibility procured, dispatched, and settled on the distribution network affects transmission constraints, as explored in 3.1.2. This will help DSOs and NESO better understand how consumer-led and DER flexibility can ease pressure on the transmission network, support CP2030, and ensure that the growing volume of smaller flexible assets can be used in a coordinated way across both distribution and transmission markets.

spenenergynetworks.co.uk

SP Energy Networks | DSO