Headroom – Whole System Thinking

NIA Closedown Report

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1. Executive Summary

The rapid growth of low-carbon distributed generation, particularly rooftop solar PV, battery storage, and emerging vehicle-to-grid services, poses both an opportunity and a challenge for the GB electricity system. While these assets offer near-zero-marginal-cost energy that can suppress wholesale prices and displace fossil-fuelled peaking plant, their connections can also create voltage and thermal constraints in the distribution network. Without a clear understanding of how much "headroom" (the capacity margin between power flow and network capacity) exists at different voltages and seasons, Distribution Network Operators (DNOs) risk either over-investing in reinforcement or unnecessarily curtailing clean generation. This innovation project set out to bridge that gap by coupling detailed network-level curtailment forecasts with whole-system market modelling, thereby translating technical headroom impacts into quantified benefits in £/MWh and CO_2/MWh.

The work brought together two specialist organisations with complementary skillsets. EA Technology Ltd led the network forecasting, supported by National Grid Distribution System Operator (DSO), leveraging its Bottom-up Transform™ modelling framework and deep experience in feeder-level voltage analysis across Low Voltage (LV), High Voltage (HV) and Extra High Voltage (EHV)[1] tiers. Their team developed and calibrated scenarios based on the National Energy System Operator's (NESO) Future Energy Scenarios, integrated storage and Vehicle to Grid (V2G) behaviour, and applied probabilistic outage and reinforcement logic. Baringa Partners, using the PLEXOS market simulation platform, handled the power-market modelling. They translated curtailment time series into system dispatch and economic outcomes, calculating wholesale price suppression, carbon-emission savings and balancing-service value under different headroom conditions.

Stage 1: Sensitivity Study and Early Outcomes (September 2023 – March 2024)

In the first stage, EA Technology constructed a "range-finding" overview by modelling curtailment on four representative days, one per season, with a focus on the summer peak when PV output is highest. This bottom-up approach revealed that, absent of any network reinforcement, solar exports would be capped by voltage-rise limits across all voltage levels, creating midday curtailment spikes. However, by excluding demand-driven uprating, realistic battery cycling and off-peak wind constraints, the study provided only a partial snapshot. Baringa then ran two market scenarios, "Network Curtailment" (low curtailment) versus "Maximum Constrained Generation" (high curtailment), to gauge potential benefits. Even with simplified assumptions made in Stage 1, the analysis found wholesale-system cost savings of £0.3 billion to £17 billion (2023–34) and carbon-cost reductions of £0.1 billion to £0.75 billion, with the largest price-suppression effects occurring in winter-evening tight-margin hours. Crucially, this sensitivity range underscored the material whole-system value of headroom release and set the priorities for deeper, year-round refinement.

Stage 2: Refined Best-View Analysis (June 2024 – March 2025)

Stage 2 enhanced the modelling to produce a "best-view" assessment. EA Technology expanded to twelve seasonal representative days, introduced demand-driven reinforcement triggers, modelled realistic Battery Energy Storage System (BESS) charge/discharge cycles and V2G uptake, and included outage statistics across HV and EHV feeders. 132kV network and Grid Supply Point constraints were considered by NGED DSO's Simple Curtailment Tool. The combined network forecast showed annual curtailed energy rising to 8.5 TWh by 2034, enough to power roughly 3.2 million UK homes, with the dominant constraint zone shifting from 132 kV in the early years to LV solar-driven voltage limits later in the decade. Baringa's PLEXOS runs then converted this curtailment series into a £2.49 billion total system benefit (2023–34), comprised of

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[1] LV – 400V, HV – 6.6 or 11kV, EHV – 33 or 66kV

£1.93 billion in wholesale-price savings, £0.21 billion in carbon-cost reductions and £0.35 billion in avoided balancing costs. Voltage sensitivity highlighted LV and 132kV networks as offering the largest benefit potential. Volume based sensitivity compared total system benefit to curtailment volume, deriving a figure of ~£100/MWh (2023/24 prices). These refined outputs now offer DNOs a robust, data-driven foundation for optimising reinforcement, flexibility procurement and regulatory engagement, as evidenced by National Grid DSO using values from the project in our FY25 Performance Panel Report.

The project ran for 18 months at a total project cost of £612,988.96.

2. Project Background

The motivation for this innovation project can be seen most clearly when viewed through two lenses: the end customer homes and businesses whose power bills, service quality and environmental impact depend on the grid's performance and NGED as a Distribution Network Operator (DNO) charged with safely, reliably and cost-efficiently delivering low-carbon electricity.

A Customer-Centric View

At its heart, this work was driven by the simple fact that customers ultimately pay for every pound the system spends. With the rapid rollout of solar PV, batteries and electric vehicles, distribution networks have begun to constrain zero-marginal-cost power exports. When these constraints force the system to run more expensive, carbon-intensive thermal plant at the margin, the extra cost is built into wholesale market prices and passed through to end users. By quantifying how much distributed generation (DG) is being unnecessarily curtailed and then showing that releasing even a few percent of that headroom can shave £2–3 per MWh off average electricity prices (and £5–6/MWh in peak solar hours), the project delivered a direct line of sight between smarter network management and lower consumer bills.

Frequent or unmanaged curtailment events not only raise costs but introduce volatility into local voltage and power quality, with knock-on effects on customer equipment e.g. electric vehicle (EV) chargers, and satisfaction. LV connected solar generation has been forecast to be impacted severely by voltage rise constraints, risking customer dissatisfaction. Through detailed feeder-level modelling, the project identified the times, voltage levels and feeder types most at risk, creating a roadmap for targeted reinforcement or advanced control measures. By releasing headroom where it delivers the greatest system benefit, customers enjoy more stable voltages and fewer unplanned interruptions, even as they connect more rooftop solar and home batteries.

Many customers chose low-carbon technologies (Solar PV, BESS, EVs) in pursuit of lower bills and environmental stewardship. However, if those assets are periodically switched off due to network constraints, the carbon savings are eroded. Our analysis shows that each MWh of DG unlocked reduces grid-average emissions by 5–10 kg CO_2 (and up to 20 kg in high-PV hours). Over a decade, this translates into millions of tonnes of avoided CO_2, directly aligning with customers' net-zero ambitions and boosting the value of their green assets.

NGED's Strategic Rationale

Under the ED2 price control, NGED must demonstrate that every pound spent on reinforcement or flexibility procurement returns value to consumers. Traditional reinforcement planning relies on conservative worst-case assumptions, often leading to premature capital outlay. By quantifying the true scale, timing and location of headroom constraints and converting them into £/MWh and CO_2/MWh metrics, the project provided NGED with a robust business-case toolkit to prioritise interventions where they deliver the highest whole-system benefit.

Ofgem increasingly encourage DNOs to coordinate with the NESO, procure flexibility services from distributed assets and embed carbon metrics into network planning. The refined "best-view" and cascading headroom analyses showed how LV voltage management, 132 kV flexibility schemes and ANM upgrades can be sequenced to maximise value for the system operator, the network operator and customers. This directly supports NGED's obligations to integrate DSO functions, facilitate the competitive flexibility market and contribute to national net-zero targets.

NESO's Future Energy Scenarios forecast a six- to eight-fold increase in DG capacity by 2035. Without dynamic, data-driven headroom forecasting, NGED risks either over-curtailing renewables, leaving stranded green assets, or under-planning reinforcement, leading to service failures. By incorporating year-round, feeder-level outage data, realistic BESS and V2G behaviour, and demand-driven reinforcement logic, the project has equipped NGED with an "early-warning" system for emerging constraints and a decision-support toolset to manage the transition with minimal stranded cost.

Finally, the joint EA Technology–Baringa approach demonstrated a clear pathway for NGED to integrate real-time network constraints into PLEXOS dispatch models and NESO market operations. This enhances NGED’s capability to participate in imbalance, balancing and ancillary services markets, opening new revenue streams and delivering further value to customers.

3. Scope and Objectives

Stage 1 scoped a high-level sensitivity study to bound the potential value of releasing distribution headroom. EA Technology built a bottom-up Transform™ model using four seasonal “statistically representative” days to map curtailment drivers at LV, HV, and EHV under static network ratings. National Grid established the ‘maximum constrained’ scenario by considering four Grid Supply Points (GSPs) using the initial, Excel based, Simple Curtailment Tool developed by National Grid’s Primary Network Design (PND) and Distribution System Operator (DSO) teams. Baringa then translated low- and high-curtailment cases into whole-system impacts via PLEXOS runs, establishing the benefit envelope and flagging key modelling gaps.

Stage 2 refined to a “best-view” analysis. EA Technology expanded to twelve seasonal days, incorporated demand-driven reinforcement triggers, realistic BESS/V2G cycling and outage de-ratings, and produced voltage-segmented curtailment series. Baringa reused PLEXOS to assess economic and carbon metrics under the enhanced curtailment inputs, providing a voltage level sensitivity, volume-based sensitivity, and more comprehensive ancillary service modelling.

The objectives set at the start of the project were met, as indicated in Table 1.

Table 1: Status of project objectives

Objective	**Status**
Develop a methodology to calculate the whole system value of network headroom.	✓
Produce representative headroom archetypes that demonstrate where headroom provides value to the energy system	✓
Quantitatively understand what parts of the network added headroom has the most significant financial benefit to the whole energy system. This will be discussed in terms of voltage level, types of connected generation, and types of connected demand	✓
Understand the constituent parts of customer bills which are most impacted by added headroom, i.e. wholesale price savings, balancing market savings, carbon savings	✓
Collated information to give values for £/MWh and CO2/MWh headroom whole system value, which will vary depending on archetype grouping	✓

4. Success Criteria

During the course of the project, all success criteria were achieved.

Table 2: Status of project objectives

Success Criteria	Status
Stage 1 Success Criteria	
• A successful expert workshop is held, with attendance from National Grid DSO, NESO, and project partners. The outcomes of the workshop have successfully directed the project towards maximum value.	✓
• A comprehensive methodology to understand the value of network headroom is produced. This should be completed in collaboration with National Grid, Baringa and EA Technology LTD. – A conceptual translation of headroom on generation, storage, and demand is produced in Stage 1, which helps understand exactly how to model headroom availability. – An understanding of how the value network headroom availability differs according to voltage level, and according to time-base scenarios. – Following detailed PLEXOS studies, understand how headroom availability changes the carbon intensity of the grid and consequently offers carbon savings.	✓
• Incorporate constraints based on a national view into PLEXOS to understand the proportion of available low carbon generation that is curtailed, which otherwise supports the merit order effect.	✓
• Develop an understanding of how the proportion of renewable generation affects the wholesale price. During Stage 1, this will be at a national level with only qualitative consideration of whether demand and generation assets are connected to the distribution network or transmission network.	✓
• Provide an understanding of the scale of benefit increased distribution headroom may have in terms of £/MWh, and CO2/MWh. At Stage 1, this will explore what times of the year the benefit is largest.	✓
• Detailed summary reports are produced for Stage 1 that outlines the methodology in detail, the sources of any data used, and presents key findings in a clear and understandable way. This should incorporate the effect additional network headroom has on other aspects of the customer bill, including balancing system costs, network costs, and carbon accounting costs.	✓
Stage 2 Success Criteria	
• A successful expert workshop is held, with attendance from National Grid DSO, NESO, and project partners. The outcomes of the workshop have successfully directed the project towards maximum value.	✓
• Develop an understanding of how the proportion of renewable generation affects the wholesale price. During Stage 2, this will be at a national level with detailed consideration of whether demand and generation assets are connected to the distribution network or transmission network.	✓
• Provide an understanding of the scale of benefit increased distribution headroom may have in terms of £/MWh, and CO2/MWh. At Stage 2, this will explore what times of the year the benefit is largest but also consider	✓

the relative split between GB wide free dispatch and the benefit gained from increased distribution network headroom.	
• Detailed summary reports are produced for Stage 2 that outlines the methodology in detail, the sources of any data used, and presents key findings in a clear and understandable way. This should incorporate the effect additional network headroom has on other aspects of the customer bill, including balancing system costs, network costs, and carbon accounting costs.	✓

5. Details of the Work Carried Out

Stage 1: Initial Sensitivity Study

Stage 1 set out to answer a simple, strategic question: is there material whole-system value in releasing distribution-network headroom? The objective was to establish credible “bookends” for that value and expose the drivers of curtailment, so that Stage 2 could focus effort where it matters most.

EA Technology produced GB-wide curtailment series using a parametric Transform™ model. Low-carbon technology uptake and siting were mapped from FES/DFES and the Embedded Capacity Register. Then, four seasonal representative days (winter/ intermediate warm / intermediate cool/ summer) were used to form net-export profiles at LV, HV and EHV. These were tested against voltage-rise and thermal limits to derive curtailment by feeder archetype, scaled to 365 days, and aggregated by voltage level and technology. Baringa then translated that curtailment series into system impacts with PLEXOS, running two framing cases: a Network Curtailment case reflecting summer PV-driven export limits, and a Maximum Constrained Generation stress-test using Simple Curtailment Tool logic and monthly export caps for flexible plant. This provided the structured inputs for the Stage 2 refinement.

Network Modelling Led by: EA Technology Ltd, supported by NGED DSO & NESO

Kick off workshop

To begin the project, a workshop was held between the project team (NGED Innovation, Baringa, EA Technology) and key stakeholders from NGED DSO and NESO. The objective of the workshop was to provide an overview of the project’s methodology and establish user-stories for how outcomes of the project may influence the business in the long term.

Within the workshop, the following assumptions were made:

- **Study years:** 2023, 2028, and 2034 were selected as the project’s study years. 2023 was chosen as the baseline year, reflecting the project’s start date and the data available at that time. 2028 was selected for its alignment with regulatory price control periods, while 2034 aligns with NGED’s Network Development Plan horizon. As the project’s outcomes are intended to inform near-term investment planning and decision-making, a later study year was not considered necessary.
- **Demand reinforcement:** Following discussion with DSO colleagues, it was decided to not consider network reinforcement for either demand or generation load growth. Thereby the value of associated headroom from the 'unconstrained' view will reflect how much any reinforcement in the intermediate years is worth.
- **Fault level reinforcement:** Active Network Management does not currently draw on real time fault level measurements to instruct curtailment. Unlike generators wishing to connect to networks experiencing thermal or voltage constraints, generators wishing to connect to networks constrained by fault level issues are not given ANM connections. It was therefore decided to exclude fault level assessments from network modelling. It was assumed FES/DFES uptake rates take fault level restrictions into account.

LCT uptake rates

Uptake projections for generation, BESS, and load technologies were sourced from NESO's[2] 2023 Future Energy Scenarios, using the System Transformation scenario due to its close alignment with NGED's Best View Scenario and Baringa's Net Zero High scenario (See Figure 1Figure 1). Alignment was 0.18% in 2023, 3.12% in 2028, and 0.14% in 2034, the projects respective study years. The Embedded Capacity Register was analysed to determine the proportion of each technology type connected at LV, HV, and EHV levels, and within rural, suburban, and urban networks. These proportions were assumed to remain constant over the modelled period, and uptake rates were allocated across the relevant network archetypes in the Transform™ model.

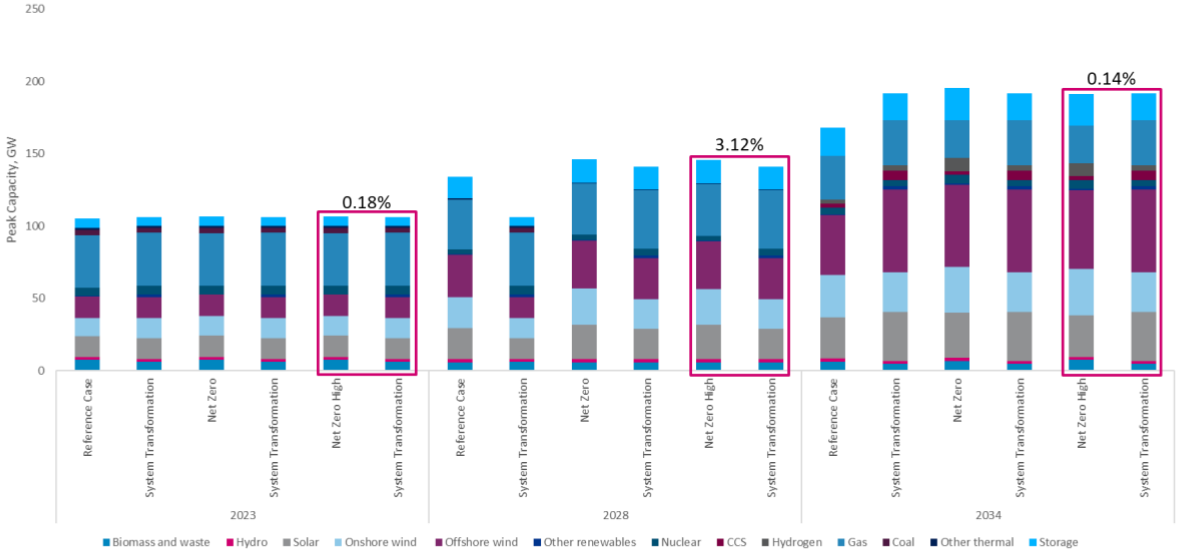

Figure 1: Alignment between Baringa's Net Zero High Scenario and NESO's System Transformation Electricity demand, generation and BESS profiles

Four seasonal profiles (Figure 2) were modelled to capture different network operating conditions: Winter Peak Demand, Summer Peak Generation, Intermediate Cool Peak Demand, and Intermediate Warm Peak Demand. Technology-specific profiles were developed for solar PV, wind, gas, BESS, heat pumps, and EV charging points, expressed in kilowatts per kilowatt peak capacity. BESS behaviour was modelled using NGED's conservative network design assumption of full export during peak generation periods and full import during peak demand periods. A scaling methodology was then applied to convert the four representative days into a full 365-day dataset using seasonal normalisation factors derived from 2022 demand data, aligned with Baringa's economic modelling year.

Stage 1: Four load profile days to represent the year

Winter Peak Demand
(Dec-Feb)

Intermediate Cool Demand
(Oct, Nov, Mar)

Intermediate Warm Demand
(Apr, May, Sep)

Summer Peak Generation
(Jun, Jul, Aug)

Figure 2: Representative days used in Stage 1's Transform modelling

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[2] At the time of the project kick-off, NESO operated under the name National Grid ESO

Feeder archetypes

The GB distribution network was represented using a set of EHV, HV, and LV feeder archetypes that reflect a range of urban, suburban, and rural environments, as well as radial and meshed construction types. These archetypes were mapped from NGED and Embedded Capacity Register data to ensure realistic representation of network topology, construction type, and customer mix across the modelled scenarios. Details of Transform™'s archetypes can be found in Appendix 1.

Transform™ assumptions

The Transform™ Model was used to create a parametric representation of the GB distribution network, incorporating technical and economic factors that influence reinforcement decisions. Maximum deployment limits for low carbon technologies were set for each property type, for example, 4 kW PV per domestic property and 15 kW battery storage for domestic premises, with larger allowances for commercial properties. Clustering assumptions were applied to reflect the uneven uptake of technologies across feeders, with socio-economic factors influencing higher concentrations in certain areas. Uptake rates for PV, BESS, EV charge points, and heat pumps were assumed to be correlated within households.

Network model development and validation

The Transform™ model was validated against GB-wide datasets to ensure representativeness. Model outputs were compared with observed data for the number of LV feeders, total LV-connected customers, and peak load. Differences were within acceptable tolerances, with the number of LV feeders within 5% of expected number of connected customers within 4%, and peak load within 2% of National Grid NESO's System Transformation dataset. This validation confirmed that the model provided a credible representation of the GB LV, HV, and EHV networks for the purpose of the study.

Post Transform™ analysis

Curtailment results from individual feeders were scaled up to network level by applying the number of feeders of each archetype within their respective clustering bins, then aggregated to obtain total values for LV, HV, and EHV networks. Curtailment was also apportioned by technology type, based on the proportion of generation each technology contributed at the time of constraint, to support the subsequent economic modelling carried out by Baringa.

Simple curtailment tool work

Within Stage 1, the Simple Curtailment Tool (SCT) was an Excel-based model developed by NGED's DSO and PND teams to forecast generator curtailment in Active Network Management (ANM) zones. Although independent of the Headroom – Whole System Thinking project, it formed part of NGED's background intellectual property. The SCT was designed to complement the Distribution Connection and Use of System Agreement Change Proposal (DCUSA DCP) 404 tool, introduced under the Access-SCR reforms, by adding the ability to consider multiple network constraints simultaneously.

Inputs to the SCT focus on network capacity, generator characteristics, and baseline demand. For each study, the model identified the three most critical constraints, defined as the points on the network with the least headroom. Effective ratings for these constraints are taken from NGED's DCP 404 Curtailment Limit Category B database. Generation connections are filtered for the study areas and categorised by whether they are firm or non-firm (ANM managed). Each generator is assigned a Point of Connection (POC), typically the nearest Bulk Supply Point (BSP), with sensitivity factors applied to determine its contribution to each constraint. Generators were further grouped by technology (wind, solar, battery, or other), with normalised half-hourly export profiles representing their output behaviour. To establish the baseline, the SCT imports 17,520 half-hourly load values (covering the 2022 study year) for each of the three identified constraints.

Curtailment was then simulated by sequentially layering generator outputs onto the baseline loading. Firm generators are added first, followed by non-firm generators ordered by Last-In-First-Out (LIFO) principles. For each half-hour, the SCT assesses whether the uncurtailed output would breach thermal capacity at any of the three constraints. If so, it calculates the maximum permissible export to remain within limits. Each new generator added to the LIFO stack must respect the net loading imposed by those higher in the order, accurately reflecting real operational curtailment.

The model produces two export profiles for every generator: an “ideal profile” showing unconstrained output and a “curtailed profile” representing the actual permitted export after constraints are applied. These profiles are then aggregated by technology type, across four NGED Grid Supply Points (GSPs), to produce representative curtailment patterns. This enables the outputs to be incorporated into PLEXOS, supporting wider system modelling and whole-system analysis.

Within Stage 1, a GSP group from each of our licence areas was studied: Alverdiscott Indian / Indian Queens from the South Wales licence area, Rassau from South Wales, Port Ham from the West Midlands, and Chesterfield from East Midlands. Their output was aggregated by technology type and provided to Baringa as the Maximum Constrained Generation scenario.

Results: establishment of two separate constraint scenarios

Two constraint scenarios were developed to inform the economic assessment. The first reflected export-driven network constraints arising from distributed generation exceeding voltage or thermal limits based on the Transform™ modelling carried out by EA Technology. The second was based on the 132kV modelling undertaken by NGED using the SCT.

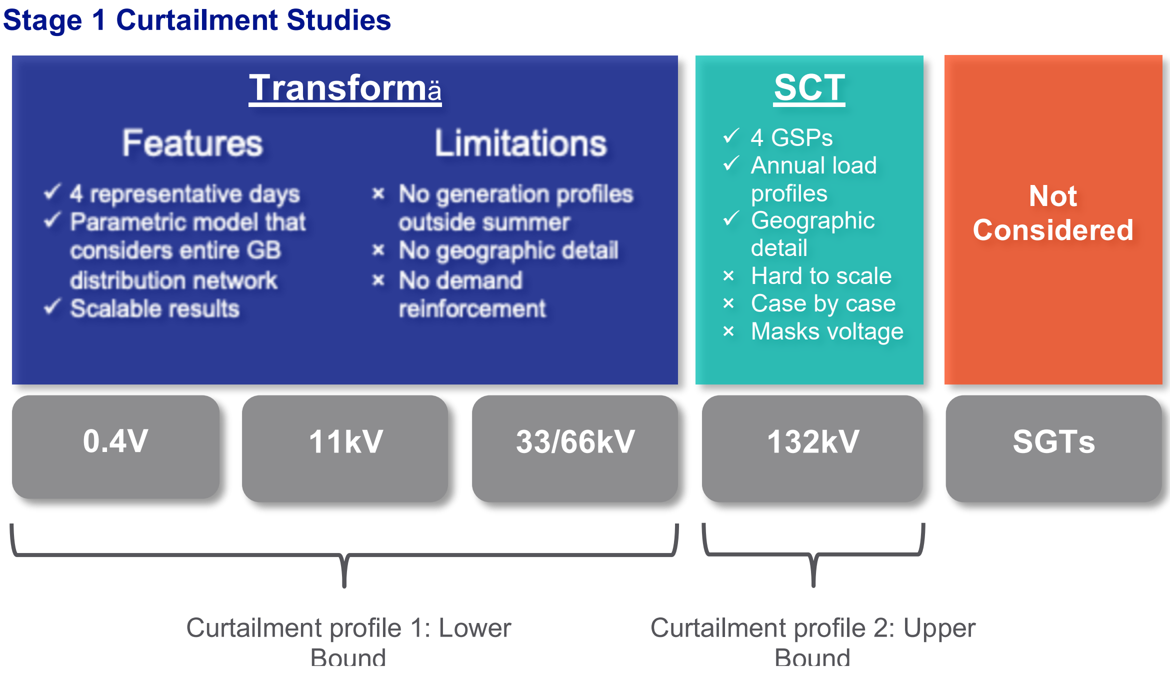

Figure 3: Stage 1's curtailment were conducted using two approaches

Stage 1: Network Modelling Output:

- Total GB Distribution Network curtailment profiles for 2023, 2028, 2034.
    - LV - EHV Transform™ model (EATL)
    - 132kV model – Simple Curtailment Tool (NGED)
- Modelling Summary Report

Power Market Modelling

Following EATL & NGED's network curtailment modelling, Baringa undertook network power market modelling. Energy Exemplar's PLEXOS[3] is a widely used power-market simulation platform that optimises unit commitment and dispatch on a least-cost basis given plant technical constraints and interconnector limits; Baringa employ it as the core engine in their GB and European market models. In this project, Baringa configured a day-ahead, hourly model of >2,000 generators from 2023–2060, representing demand in structured segments and capturing operational constraints to produce economically rational dispatch and prices. Curtailments from EA Technology were incorporated as additional fixed load at the transmission–distribution boundary, and two cases were run: a counterfactual with no distribution curtailment, and an instance including the "Best-View" curtailment series. Inputs and trajectories followed Baringa's Net Zero High scenario (aligned to FES System Transformation), ensuring consistency with wider decarbonisation assumptions. This set-up allowed the team to quantify wholesale price and emissions impacts attributable to releasing distribution headroom in a transparent, system-wide framework.

Current, and future generation capacity forecasted in PLEXOS

The analysis used the Embedded Capacity Register (ECR) to identify the installed and planned distributed generation, BESS, and demand-side response capacity connected to the network, cross referenced to the volumes used by EATL in their analysis. This was combined with technology capacity assumptions from Baringa's Net Zero High (NZH) scenario, which sets a pathway consistent with achieving net zero targets by 2050. The NZH scenario provided the long-term view of technology deployment, capacity mix, and operational characteristics. Installed capacities from the ECR were mapped to corresponding technology categories within the NZH dataset, ensuring alignment between current network data and future projections. Where ECR data was incomplete or did not specify technology type, reasonable assumptions were applied based on connection size, commissioning date, and typical technology characteristics for that size and time.

Network curtailment analysis

The network curtailment analysis incorporated results from the preceding network modelling work, which established two scenarios, translating half-hourly curtailment outputs for each technology into inputs for the market model. Curtailment volumes were allocated to the corresponding generation types according to their share of generation during the constrained periods. This ensured that the curtailment profile within the market model reflected both the timing and magnitude of network constraints, as well as the technology mix affected. Curtailment was modelled as a direct reduction in available generation capacity, impacting the potential for wholesale market and ancillary service participation in those periods.

Curtailment profiles used in PLEXOS

The results of this methodology were prepared to feed into wider market and system impact assessments. The outputs included time series datasets of technology-specific generation availability, incorporating both ECR-based installed capacities and projected growth from the Baringa NZH scenario, adjusted for curtailment impacts. These datasets enabled subsequent analysis of revenue potential, market share evolution, and the system-wide implications of curtailment under a net zero aligned capacity trajectory. Three scenarios were modelled as detailed in Table 3.

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[3] https://www.energyexemplar.com/plexos

Curtailment Scenario 1: Network Curtailment scenario – Transform™

In this summer-only case, EA Technology's "Network Model" curtailment (constructed from DFES representative days) was translated by Baringa into PLEXOS as hourly, month-specific adjustments to distribution-connected generation. The treatment preserves the physics of the underlying constraint: solar PV (and to a lesser extent onshore wind) are curtailed around midday when export-driven voltage/thermal limits bind, while dispatchable technologies (distribution-connected gas and BESS) are subject to month-specific export limits so that their availability never exceeds the maximum curtailed share implied by the network model. The effect is a focused, PV-led curtailment pattern in June–August that scales over time with installed capacity but remains largely confined to bright summer hours, battery charging behaviour is not constrained in this set-up, so annual BESS energy throughput is broadly unaffected even though peak exports are capped. Figure 4 Figure 4highlights the July 2034 'mean day', presenting the revised profiles, and overall curtailment volumes in this scenario. Using EATL's work to scale results from representative days into an annual profile, the average curtailment for each study year was established, with Figure 5 showing an example of July 2034's curtailment.

Table 3: Summary of Stage 1's modelling scenarios (taken from Stage 1 report)

Scenario	Curtailment Simulation	Years Simulated	Curtailed Months	System Benefit Result
Counterfactual	None	2023, 2028, 2034	None	-
Curtailment Scenario 1: Network Curtailment	Transform™	2023, 2028, 2034	Jun - Aug	Estimated lowest level
Curtailment Scenario 2: Maximum Constrained Generation	SCT	2034	Jan - Dec	Estimated highest level

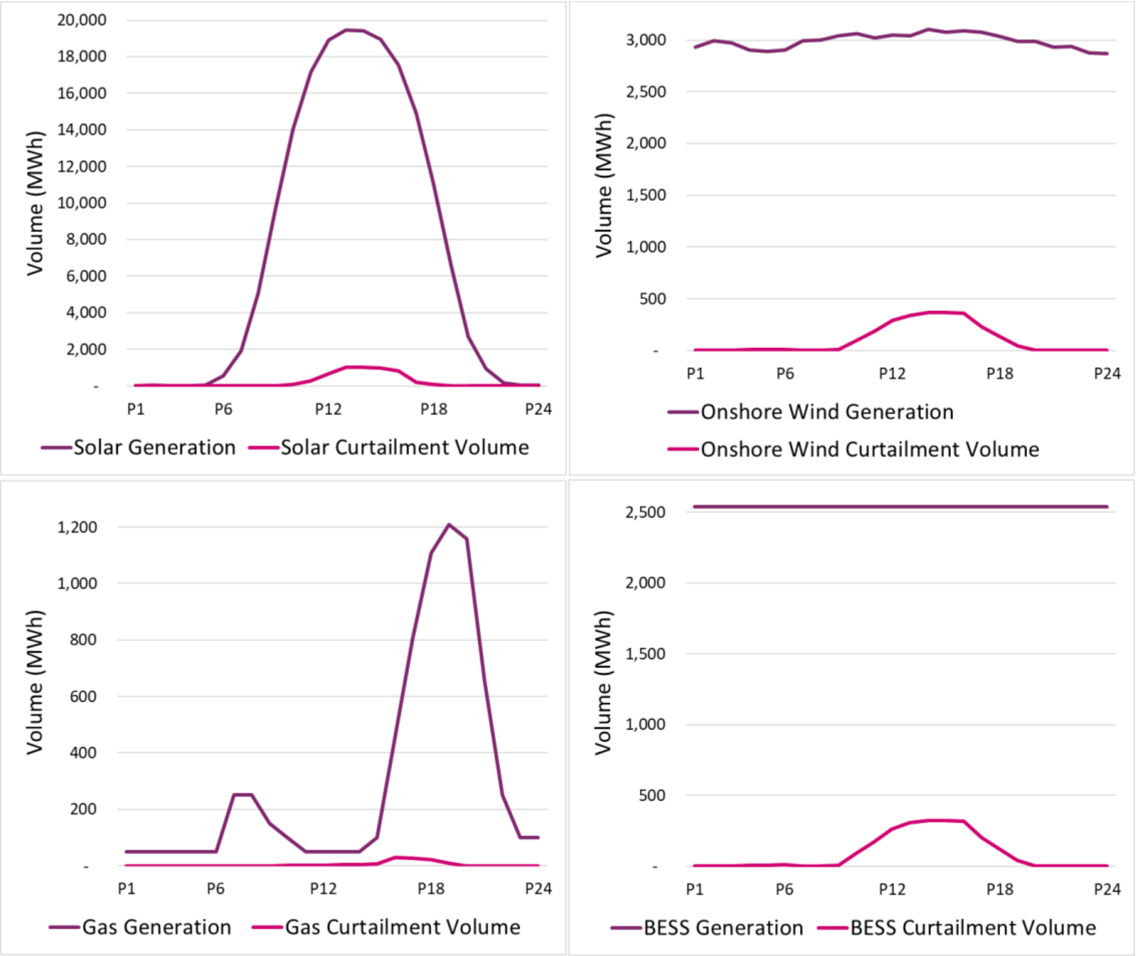

Figure 4: July 2034 mean day - Network Model aggregated curtailment and generation volume dataset (Stage 1 report)

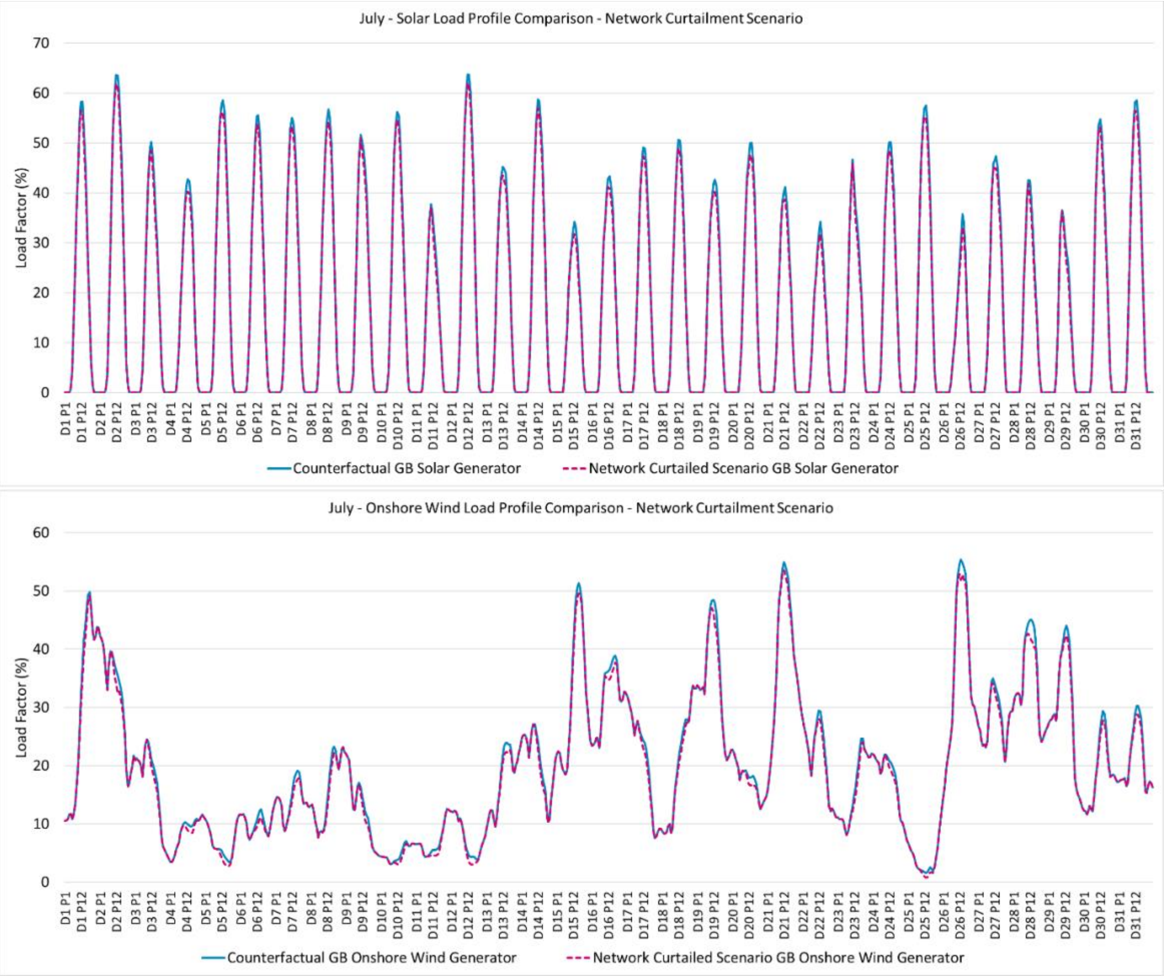

Figure 5: July 2034 - RES Comparison of Load Profiles, Network Curtailment (Stage 1 report)

To gain an understanding of the magnitude of distribution generation curtailment, the cumulative monthly export for each technology type was presented in

Figure 6 for each study year, for solar and wind exports. The gap between the counterfactual (unconstrained) case and the Network Curtailment scenario widens over time, reaching its peak in 2034 as curtailment in the Network Model rises. By 2034, simulated curtailment totalled about 400 GWh for solar and nearly 1,000 GWh for onshore wind, equivalent to 3.8% and 5.6% of their generation in the relevant summer months, or 1.5% and 1.2% of annual output respectively. Of the three summer months, June sees the greatest impact. As the Network Model's curtailment closely tracked solar PV output, this scenario may understate additional wind curtailment that can occur during winter peak periods as the model did not contain full seasonality.

Figure 6: Monthly (June-August) RES generation in the counterfactual, Network Curtailment (Stage 1 report)

Curtailment scenario 2: Maximum constrained generation – Simple Curtailment Tool

The second scenario established an upper-bound test. It used NGED’s Simple Curtailment Tool to represent distribution-level thermal limits across all months, assuming the LIFO connection stack proceeds without additional headroom investment. Baringa converted the SCT half-hourly outputs into monthly mean-day curtailment profiles for solar and onshore wind, then applied the profiles hour-by-hour to the counterfactual generation. For distribution-connected gas and BESS, they implement a monthly “maximum dispatch capacity” so that these technologies cannot exceed the SCT-implied constrained share at any hour of that month. Compared to the summer-only case, this produces materially larger, year-round curtailment with clear seasonality: deep midday curtailment of PV in high-insolation months, lower PV curtailment in winter, and persistent (though smaller than other technology types) constraints on onshore wind when windy conditions coincide with local export limits. Figure 7 presents the materially larger curtailment volumes witnessed on the average July day, still dominated by solar PV export, but indicating a much larger overall volume of lost generation than witnessed in scenario 1’s lower bound.

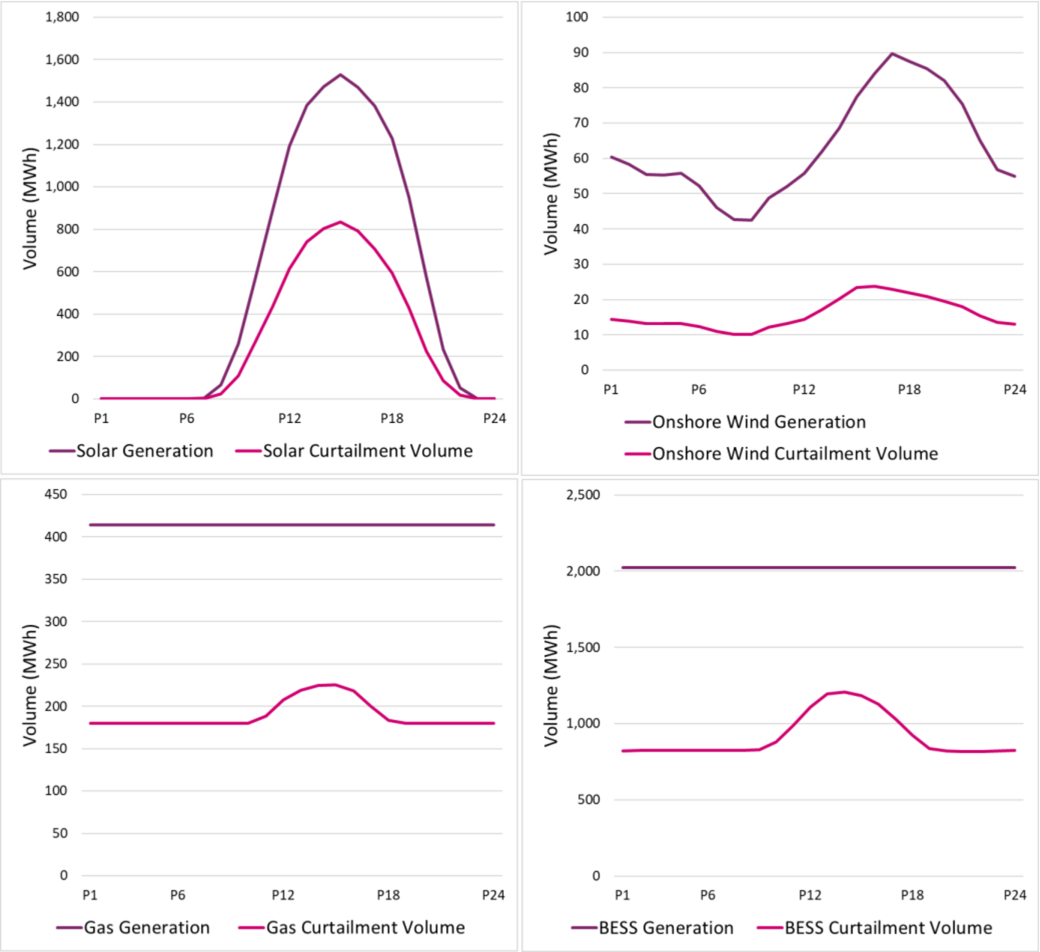

Figure 7: July 2034 mean day, SCT aggregated curtailment and generation volume dataset ([Stage 1 report](#))

Since scenario 2 considers the entire year, curtailment results for winter were possible. Figure 8 presents curtailment volumes for the average winter day. As expected, solar PV output is considerably lower than summer months, and the curtailment profile is more dominated by BESS, wind, and gas.

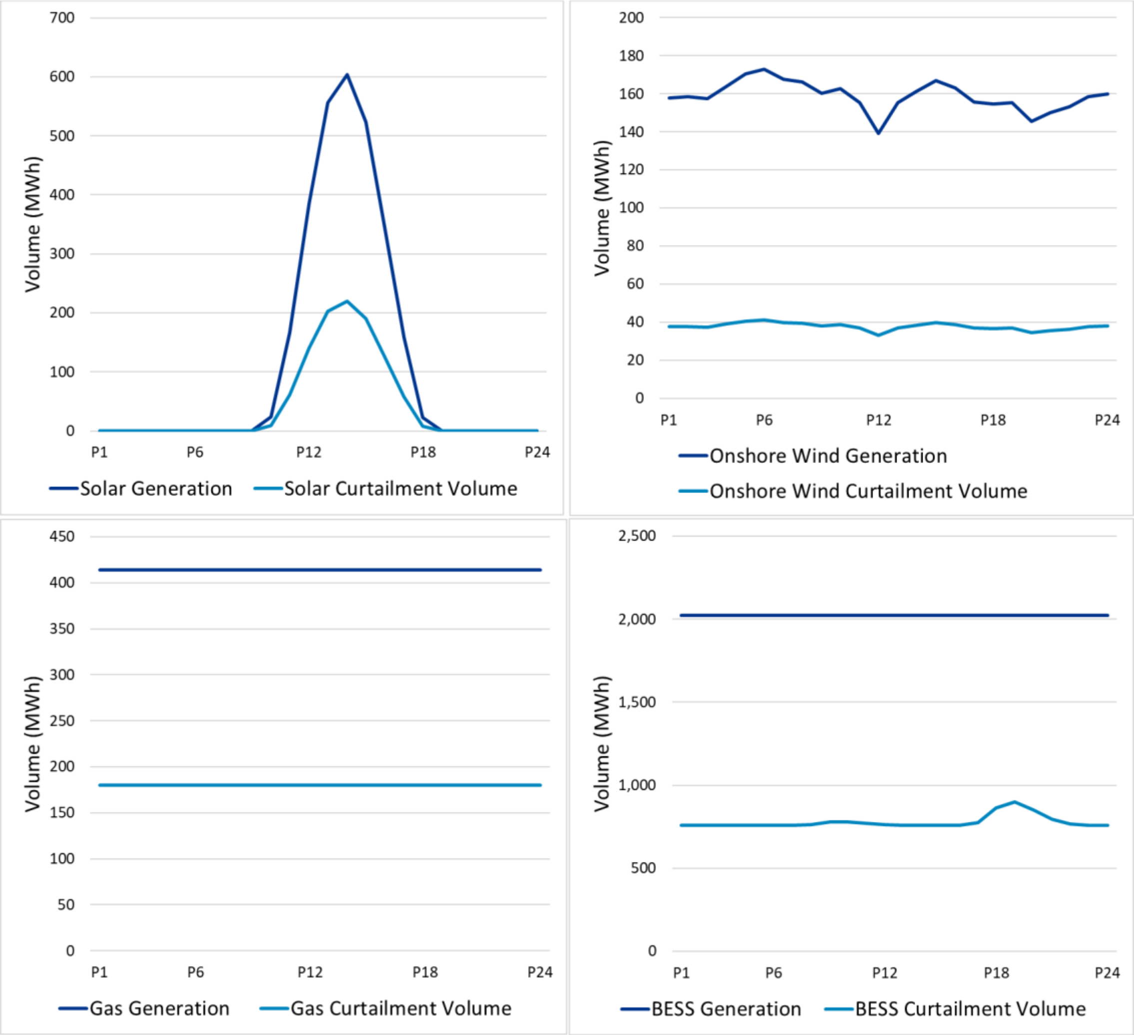

Figure 8: January 2034 mean day, SCT aggregated curtailment and generation volume dataset ([Stage 1 report](#))

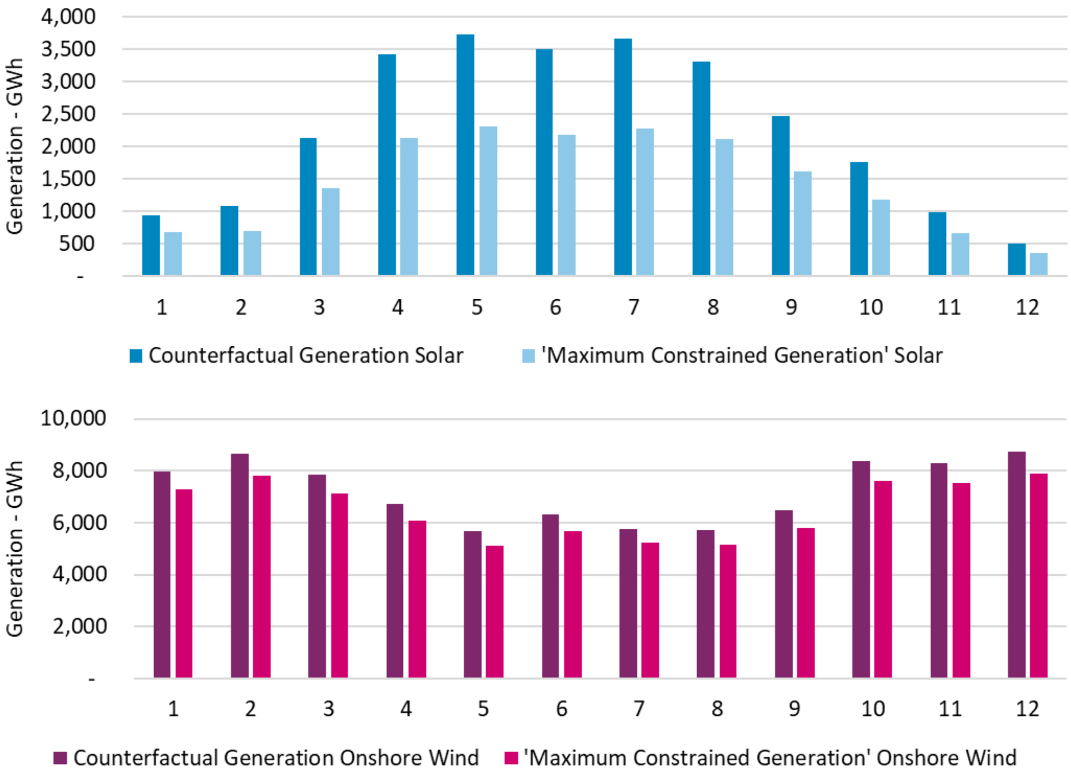

Figure 9: Monthly RES generation in the counterfactual, Maximum Constrained Generation 2034 (Stage 1 report)

Unlike scenario 1, a full annual profile was constructed, Figure 9 presents the cumulative monthly export for solar and onshore wind export under the counterfactual and constrained scenario. Substantially greater curtailment was witnessed in this scenario, extending across all months. Solar PV had the greatest curtailment in the summer months, with wind experiencing curtailment year-round.

Comparison of curtailment scenarios

Together, the two approaches signposted a credible range. The Network Curtailment scenario isolated the realistic, summer-dominant PV export constraint that DNOs are already observing on the LV - EHV network; it is pragmatic for messaging and aligns with near-term operational experience. The Maximum Constrained Generation scenario is an intentional stress-test: it shows how constraints could look if distribution limits bind more broadly through the year and if flexible assets (BESS, distributed gas) are capped to reflect those limits every month. Table 4 presents a summary of curtailment volumes across both scenarios for each generation technology type.

Table 4: Summary of RES curtailed volumes, both scenarios (Stage 1 report)

		'Network Curtailment' scenario			'Maximum Constrained Generation' scenario
		2023* Jun - Aug	2028* Jun - Aug	2034* Jun - Aug	2034
Solar PV Curtailment Volume	GWh	83	271	401	9,953
Solar PV Curtailment Volume vs Solar PV Counterfactual Generation (for relevant months)	%	1.5%	3.1%	3.8%	36.2%
Onshore Wind Curtailment Volume	GWh	29	324	996	8,210
Onshore Wind Curtailment Volume vs Onshore Wind Counterfactual Generation (for relevant months)	%	0.4%	2.3%	5.6%	9.5%
Gas Curtailment Volume	GWh	74	65	82	9,953
Gas Curtailment Volume vs Counterfactual Generation (for relevant months)	%	1.5%	1.7%	6.2%	24.4%

Impact on wholesale market prices

After the curtailment profiles were established in PLEXOS, Baringa were able to perform wholesale market analysis, indicating the difference in price between the counterfactual scenario and each of the curtailment scenarios. A comparison between the counterfactual scenario and each curtailment scenario is provided in Table 5, illustrating the lesser effect observed using scenario 1, and a much greater effect observed using scenario 2.

Table 5: A summary of the system cost impact for both scenarios ([Stage 1 report](#))

		'Network Curtailment' scenario (Jun-Aug of each year)			'Maximum Constrained Generation' scenario
		2023*	**2028***	**2034***	**2034**
Load	GWh	61,763	71,557	98,944	463,591
Counterfactual Price**	£/MWh	£75.27	£73.37	£66.58	£88.09
Curtailed Scenario Price**	£/MWh	£75.30	£73.59	£67.25	£94.15
Price Difference (Curtailed – Counterfactual)	£/MWh	£0.03	£0.22	£0.67	£6.06
System Cost Impact (Benefit of releasing Headroom across GB)	£m, real 2023	£1.73	£15.80	£66.12	£2,810.37
Impact relative to total system cost (Jun – Aug)	%	0.04%	0.30%	1.00%	6.88%
Impact relative to total system cost (Jan – Dec)	%	0.01%	0.06%	0.21%	6.88%

**These years only aggregate for June until August, as that is the affected curtailment period in the 'Network Curtailment' scenario*

*** Summer month prices are typically much lower than winter. So full annual price for 2034 would be higher than summer average price in 2034*

To calculate the system cost impact, consumer load was multiplied by the wholesale price, with the difference in overall cost between each scenario and counterfactual being the potential benefit available from increasing headroom.

For the 'Network Curtailment' scenario, the system cost impact of Headroom is estimated as £66m/year by 2034. This impact is considered conservative as it is incurred for only the summer period; the benefit is 1% of the total system cost during the summer period and 0.21% on annual basis. Aggregated over the 12-year period with intermediate years based on linear interpolation, the overall impact on system costs is approximately £324 million, an equivalent average annual impact of £27 million.

For the 'Maximum Constrained Generation' scenario, the system cost impact of Headroom is estimated at £2.8 billion in 2034. This is for the entire year and represents an upper limit as it has a very high level of generation output constraint. The wholesale power price increases by £6/MWh on annual level, with the most pronounced effect observed between April and June; this has a significant impact on consumer bills. The total impact on system cost over the 12-year period, with linear interpolation for the intermediate years, is estimated to be around £16.9 billion, which corresponds to an average annual impact of £1.4 billion. This is a substantial sum, demonstrating a significant potential saving from releasing Headroom on GB distribution network. In relative terms, it represents around 7% of total system cost in wholesale power market over the year.

The results provide the potential range of how much system benefit could be achieved by releasing Headroom across 12 years, with the lower end in ''Network Curtailment' scenario' at ~£324 million (~£27m annually) and 'Maximum Constrained Generation' scenario ~£17 billion (~£1.4bn annually).

Impact on carbon emissions

The impact to carbon emissions was also calculated as a key output of the analysis. The total system emissions based on fuel usage was calculated in PLEXOS, relative to the counterfactual scenario. It was observed that when RES generation is curtailed across the distribution network, higher carbon generation is required to increase its export. In sum, over 2023–2034, releasing distribution headroom delivers a materially lower carbon-cost impact under the summer-only Network Curtailment case (~£116 m total; ~£10 m a year) than under the year-round Maximum Constrained Generation case (~£753 m total; ~£63 m a year)[4]. The difference is starkest in 2034: the constrained case drives about 0.79 Mt additional carbon emissions, almost sixteen times the Network Curtailment outcome for the same year, because widespread RES curtailment forces more thermal generation, adding roughly £125.5 m to system costs. Across the whole period, the emissions that could be avoided by headroom relief span ~0.7 Mt (Network Curtailment) to ~5 Mt (Maximum Constrained Generation).

Table 6: Summary of system carbon impact for both scenarios ([Stage 1 report](#))

		Scenario 1 (Transform™)				**Scenario 2 (SCT)**
		2023	**2028**	**2034**		**2034**
Carbon Emission in Counterfactual	Mt	41.95	23.47	1.92		1.92
Carbon Emission in Curtailed scenario	Mt	42.03	23.59	1.97		2.71
Difference (Curtailed – Counterfactual)	Mt	0.09	0.11	0.05		0.79
UKA + CPS Price*	£/tonne	£58.27	£119.99	£158.71		£158.71
System Carbon Cost Impact (Carbon savings if releasing headroom)	**(£m, real 2023)**	**£5.0**	**£13.3**	**£8.1**		**£125.5**

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[4] Linear interpolation was used to establish the average annual emissions, detailed in the Stage 1 report.

Ancillary service – market participation by technology type

Participation in ancillary services markets was modelled by technology type, drawing on historical market data, operational constraints, and technical capability. The modelling considered which technologies could feasibly participate in services such as frequency response, reserve, and reactive power provision. Market participation rates were informed by past participation trends, technology-specific availability patterns, and technical restrictions such as minimum capacity thresholds and response times. For emerging technologies with little historic market presence, participation potential was inferred from trial data, manufacturer specifications, and relevant case studies. A summary of how technologies translate to the specific ancillary services is provided in Table 7.

Table 7: Mapping of ancillary services to technologies

Services[5]	Market	Battery	DSR	EVCP[6]	Gas Engine	Hydro run-of-river	Solar PV	Wind onshore
Dynamic Containment (high and low)	BS	Yes	No	Yes	No	No	No	Yes
Dynamic Moderation (high and low)	BS	Yes	No	Yes	No	No	No	Yes
Dynamic Regulation (high and low)	BS	Yes	Yes	Yes	No	No	No	Yes
Mandatory frequency response (primary, secondary, high)	BS	Yes	Yes	No	No	Yes	No	Yes
Static Recovery	BS	Yes	Yes	Yes	No	No	No	Yes
Quick reserve (positive and negative)	BS	Yes	Yes	Yes	No	No	No	Yes
Slow reserve (positive and negative	BS	Yes	Yes	Yes	Yes	No	No	Yes
Reactive power (Voltage)	BS, DNO	Yes	Yes	Yes	No	No	No	Yes
Stability	BS	Possible	No	No	No	Yes	No	Yes
Constraint Management	BS	Yes	No	No	No	No	No	Yes
Restoration (black start)	BS	Yes	No	No	Yes	No	Yes	Yes
Balancing Mechanism	BS	Yes	Yes	Yes	No	Yes	No	Yes
Capacity market	ESO	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Wholesale	W'sale	Yes	Yes	Yes	Yes	Yes	Yes	Yes

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[5] NESO: DNO services are excluded as they are unlikely to provide wider system benefits.

[6] Electric Vehicle Charging Point

BM Energy Imbalance Costs are highly weather-dependent, ranging from about £6m to over £100m per year (2019–2023), with occasional months where NESO earns up to ~£10m. Even so, they're tiny relative to the wholesale market (roughly £100m vs £40bn, ~0.25%). Baringa assessed distribution-level curtailment impacts in the BM using its GB BM model but simulated only the Network Curtailment case, as the Maximum Constrained Generation volumes exceed total BM cleared volumes. The BM modelling mirrors the Day-Ahead set-up: the same hourly curtailment for onshore wind and solar is applied, and the same maximum-generation caps constrain gas and BESS redispatch.

Table 8: Summary of BM Energy Imbalance Cost Impact

		'Network Curtailment' scenario		
		2023	2028	2034
BM Energy Balancing Cost Change relative to Annual Total	%	0.4%	-1.2%	-0.2%
Assumed BM Energy Imbalance Cost*	£m	£51	£51	£51
BM Cost Impact (Benefit of releasing headroom)	**£m**	**£0.18**	**-£0.62**	**-£0.10**

**Assumed BM Energy Imbalance Cost is based on the average value of historical 2019 – 2023 BM Energy Imbalance Cost published by NESO (National Grid NESO at time of authoring)*

Baringa set out why balancing services matter in the context of distribution headroom. Although wholesale and network costs dominate the customer bill, they identified the channels through which changes in distribution headroom could influence those costs, principally by altering access to lower-cost flexibility and the need for higher-cost alternatives when the distribution network is constrained. Although Stage 1 did not directly model balancing-services outcomes, it described how headroom reductions can either limit access only during the constrained hours, or, at the other extreme, deter distribution-connected providers from offering services at all if they cannot guarantee availability. The true effect will sit between these bounds and depends on service design; commitment lead times and the predictability of constraints.

To delve into this effect, the current cost context using NESO data was established. In 2022/23, around 43% of balancing-services expenditure (~£1.8bn) related to managing transmission constraints, with a further 23% spent collectively on reserve products. This frames the potential materiality of better distribution headroom and coordination for system costs borne by consumers. In the Stage 1 report, this cost breakdown is shown graphically and used to motivate why any headroom-driven change in who can deliver services, and when, could shift the overall Balancing Services Use of System (BSUoS) burden.

For an initial estimate of benefits, the report draws on NGED's earlier NIA project on the "Optimal Coordination of Active Network Management (ANM) Schemes and the Balancing Services Market." Rather than adopting absolute figures from that project (given system changes since 2019), Stage 1 adopts £/MW benchmarks by technology to illustrate the order of magnitude of coordination effects. Indicative values cited include: ~£1.0k–£1.3k per MW-year consumer cost where ANM counteracts accepted wind/solar bids, ~£2.9k per MW-year for gas where ANM counteracts accepted bids/offers, and the lost benefit from non-participation of ~£0.8k–£3.3k per MW-year (solar/wind) and ~£162k per MW-year (gas). The NIA work reported potential coordination savings of £30m–£138m per year, which Stage 1 treats as conservative anchor points given that balancing-services costs have risen since that study.

The key risks if ANM and NESO procurement are not aligned include:

- non-delivery risk where ANM curtails providers after they are instructed, exposing them to penalties.
- unnecessary exclusion of ANM-connected providers from services, reducing market liquidity.
- counteraction risk, where NESO actions are nullified by local ANM curtailment; and
- over-reaction risk, where fast ramping by one provider forces tripping of an ANM-managed unit. The report uses these findings to emphasise the need for coordinated design and operation of ANM with NESO markets to avoid eroding consumer value.

A lack of headroom can also deter otherwise viable connections (removing flexibility from the system entirely), push assets toward timed connections (restricting availability in the hours services are needed), or leave ANM-connected assets technically available but unable to guarantee delivery due to uncertain curtailment windows. Each pathway alters the pool of deliverable balancing services and therefore system costs, reinforcing the central case for targeted headroom relief and better ANM-NESO coordination

Stage 1: Market Modelling Output

- Wholesale market modelling undertaken for two scenarios: upper and lower bound.
- Power Market Modelling Report

Stage 2: Refined Modelling

The end of Stage 1 SME workshop, attended by DSO colleagues, provided feedback on the results and approach taken. The limitations of Stage 1's modelling were discussed, notably:

- the lack of a combined curtailment profile which included all voltage levels,
- the exclusion of winter and intermediate generation profiles,
- use of fixed asset ratings, with no regard to demand driven reinforcement,
- no consideration of abnormal running arrangements

Taking this feedback on board, the project revised the delivery plan (detailed in Section 7) and focussed on establishing a single combined curtailment profile encapsulating both Transform™ and SCT methodologies, with updates made to address previous limitations.

Baringa's market modelling conducted exploratory data analysis, conducted volume and voltage level sensitivity studies, and expanded the detail of ancillary service modelling.

1. Network Curtailment forecasting

Transform

- ✓ Seasonal load profiles for generation with 12 rep days
- ✓ Abnormal running conditions
- ✓ Improved battery profile
- ✓ Demand reinforcement
- ✓ Use of V2G technology profiles
- ✓ Integration with SCT

Results from both methodologies are combined into a single curtailment profile overlapping at 33 – 66kV

SCT

- ✓ 17 GSPs studied
- ✓ 132kV and transmission constraints
- ✓ Python scripted to improve scalability
- ✓ Up to 8 constraints per GSP group
- ✓ Scaled up to represent UK wide connection volumes.

A single hourly curtailment profile was established, covering all voltage levels and technology types

2. Power Market Modelling

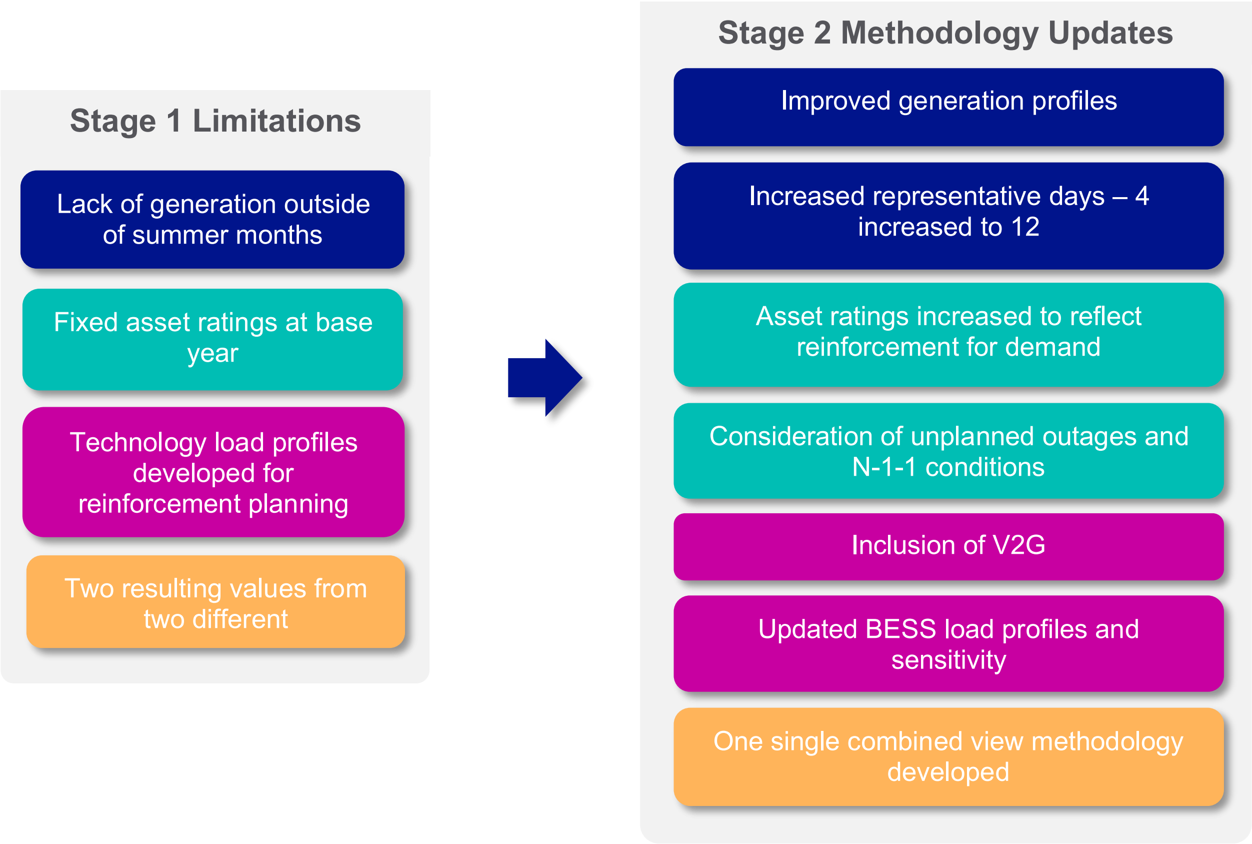
Wholesale market modelling

- ✓ Exploratory data analysis
- ✓ Curtailment result summary
- ✓ Voltage level sensitivity
- ✓ Curtailment volume impact assessment

Ancillary service modelling

- ✓ Analysis of balancing services
- ✓ Forecasted market sizing
- ✓ Curtailment impact assessment methodology
- ✓ Results and recommendations

Figure 10: Stage 2's modelling updates and approaches



Stage 1 Limitations

- Lack of generation outside of summer months
- Fixed asset ratings at base year
- Technology load profiles developed for reinforcement planning
- Two resulting values from two different

Stage 2 Methodology Updates

- Improved generation profiles
- Increased representative days – 4 increased to 12
- Asset ratings increased to reflect reinforcement for demand
- Consideration of unplanned outages and N-1-1 conditions
- Inclusion of V2G
- Updated BESS load profiles and sensitivity
- One single combined view methodology developed

Improved seasonal profiles

The modelling approach refined the seasonal demand and generation profiles used in Stage 1 by incorporating additional representative days (12 days rather than 4) and adjusting scaling factors to better match observed 2022 demand data. This allowed for more accurate representation of variations between weekdays and weekends, as well as capturing shoulder-season behaviour more precisely. Updated technology-specific profiles for solar PV, wind, and other distributed energy resources were applied, ensuring that the model reflected both seasonal and intra-seasonal variability in generation and demand patterns.

EA Technology produced 12 new generation profiles, providing a better representation of generation throughout a year. These profiles are:

- Winter (December, January, February) – Peak Generation Day, Average Day, Peak Demand Day.
- Intermediate Cool (March, April, November) – Peak Generation Day, Average Day, Peak Demand Day.
- Summer (June, July, August) – Peak Generation Day, Average Day, Peak Demand Day.
- Intermediate Warm (May, September, October) – Peak Generation Day, Average Day, Peak Demand Day.

Where:

- Peak Generation Day = High levels of generation, low levels of demand load.
- Average Day = Median levels of generation, median levels of demand load.
- Peak Demand Day = Low levels of generation, high levels of demand load.

A data workbook containing the seasonal profiles used for all technologies within Transform™ is available on the project webpage. The full methodology for how 12 representative days were established for demand and different generation classes is available within the Stage 2 Curtailment Modelling report.

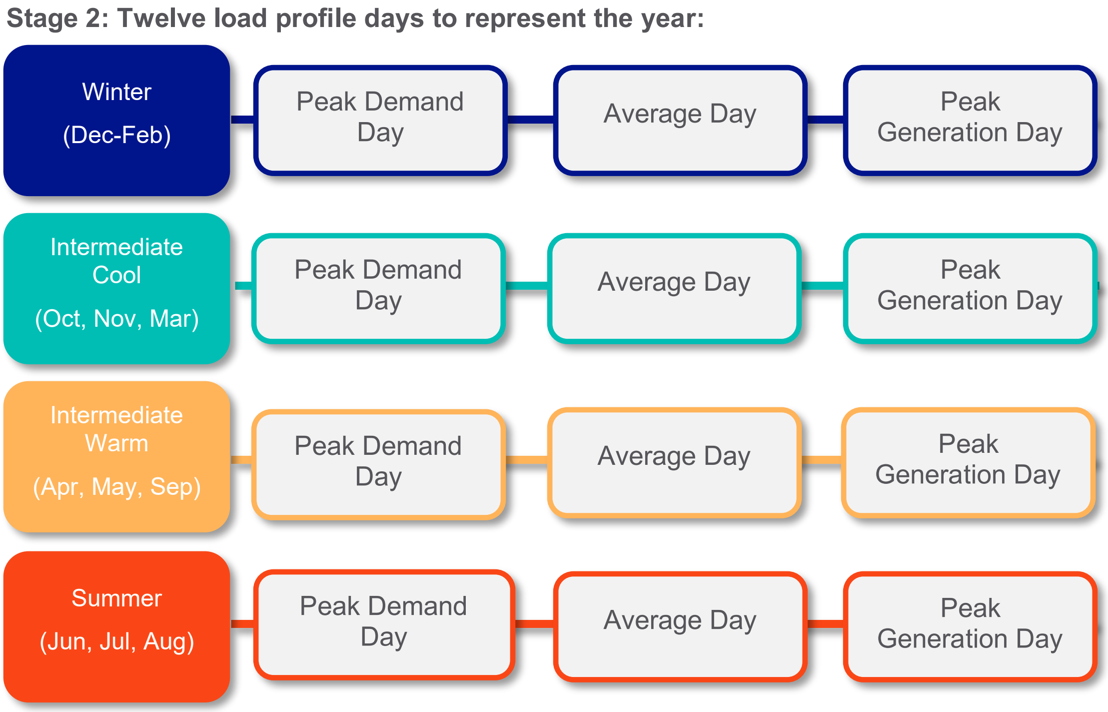


Figure 11: Load profiles produced from SCT 365-day load profile

Statistical analysis comparing the total season load from the SCT and the total load within a season produced from scaling three representative days (total load is calculated from the area under the load profile) found immaterial difference between approaches.

Table 9: Statistical analysis comparing SCT and representative days

Season	Area Under Load Profile (SCT)	Area Under Load Profile (Scaled)	Difference	Difference (%)
Summer	1832.88	1833.20	0.3169	0.0173
Winter	1535.30	1535.37	0.0676	0.0044
IC	1900.28	1909.14	8.8566	0.4661
IW	1680.01	1667.50	12.5100	0.7446

Vehicle to grid

Vehicle-to-grid (V2G) capability was introduced into the modelling to capture the potential impact of electric vehicles providing export to the network. The assumption was that V2G-capable vehicles would discharge during peak demand or network constraint periods, based on availability and user behaviour profiles. Data from CrowdCharge, NGED's real-world V2G trial, was used as the demand profiles, as illustrated in Figure 14. The uptake rates for V2G were aligned with projections from the 2023 System Transformation Future Energy Scenario, and export capacities per vehicle were based on manufacturer specifications and trial data. This inclusion allowed the modelling to assess the effect of V2G on both network constraints and curtailment volumes.

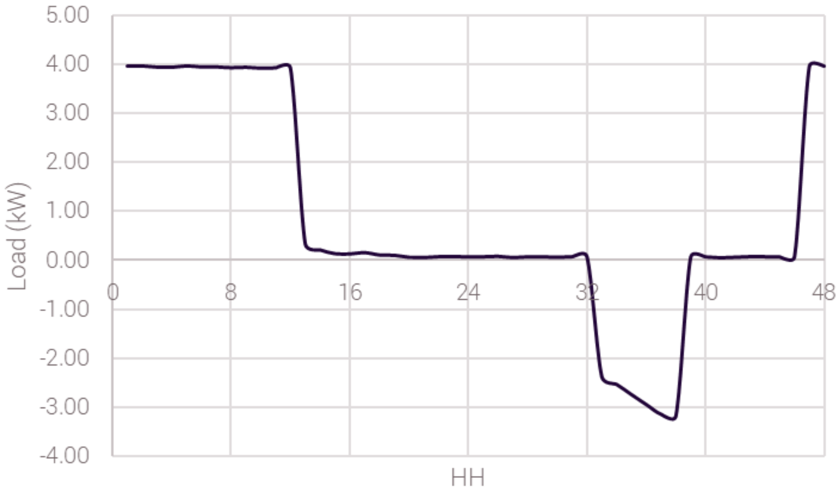


Figure 12: V2G charging/discharging profiles

Demand reinforcement

In Stage 1, network capacity was assumed to be fixed, making no account of demand led reinforcement. To provide a more realistic view of network headroom, Stage 2 introduced an assessment of demand led network reinforcement.

For LV and HV networks, demand-led network reinforcement requirements were modelled by identifying cases where peak demand exceeded thermal or voltage limits in the Transform™ network model.

Due to the larger scale of the works at EHV level, the distribution network is not necessarily upgraded for demand directly as constraints are met. Instead, reinforcement at EHV will be planned as part of a DNOs business model. As such, reinforcement at EHV level within the analysis of the Transform™ results must be considered differently than LV and HV archetypes within Stage 2 of this project.

To determine when archetypes may be expected to be reinforced, EA Technology analysed planned reinforcement upgrade data for NGEDs network based on ED2 business planning. From this it was determined that out of 73 reinforcement upgrades, 28 (38%) were at the EHV level. The analysis also identified the spread of trigger times and archetype assignments.

The result of this analysis was incorporated into Transform™, to update the capacity of each feeder archetype according to when reinforcement would be carried out. Full details can be found in the Stage 2 Curtailment Modelling report.

Table 10: Number of reinforcement upgrades by year

Trigger Year	Number of Reinforcement Upgrades	Cumulative % Reinforcement Upgrades
2025	9	32%
2026	5	50%
2027	6	71%

2028	3	82%
2029	1	86%
2030	1	89%
2031	2	96%
2032	0	96%
2033	1	100%

Table 11: Number of Reinforcement Upgrades by Network Archetype

Archetype	Number of Reinforcement Upgrades	Percentage of total
Rural	14	50%
Suburban	6	21%
Urban	8	29%

Abnormal running

The abnormal running analysis assessed the impact of temporary network configurations, such as those required during planned maintenance or fault conditions, on curtailment. In these scenarios, sections of the network operate outside their usual topology, which can reduce available capacity and increase the likelihood of constraints. The modelling simulated abnormal running conditions across representative archetypes to quantify the additional curtailment risk under these circumstances.

Historic outage data from our outage management system, containing all recorded outages from 2000 - 2024 was provided to EA Technology, and mapped to Transform™ Archetypes. The 24 years of data was assessed, to identify what a ‘typical outage season’ may look like for representative analysis. 2021 was determined to be the most representative year for a full assessment. Prior to 2016, no HV outages were recorded in the data, so they were removed from the data. 2016 also experienced a higher than usual number of outages on rural networks, which was discounted, and as 2024 had not experienced a full year at the time of work, was also discounted. Outages between 2017 – 2023 were analysed further, to extract the average number of outages, average outage duration, and total outage duration. Between 2017 and 2023 the average of the total sum, average and count of planned outages were calculated as follows:

- Average sum of planned outage duration between 2017 and 2023 – 2190 hours
- Average of planned outage duration between 2017 and 2023 – 3.62 hours
- Average count of planned outage duration between 2017 and 2023 – 583 hours

In all cases the years 2018 and 2021 had the closest yearly values to these averages. EA Technology therefore believed that using the outage data from one of these two years will give a good reflection of a typical year of planned outages NGEDs network. The best choice for a typical year was determined as 2021, as it is close to our study year and has a delta of only 0.84% to the yearly average between 2017 and 2023. The days during which the NGED network is in planned outage configuration was then extracted from the outage data for the whole of 2021.

During periods of planned outage, the asset ratings of the archetypes within Transform™ will be derated based on a worst-case network design. Based on P2 recommendations the asset rating for the different Transform™ archetypes at HV and EHV as a worst-case scenario network design are as follows:

- **HV networks** (P2 recommendations class D) N-1-1 redundancy of 1/3 group demand in 3 hours. Asset ratings will therefore be derated to zero for the first 3 hours of a planned out and 1/3 of their original ratings for anytime greater than 3 hours.
- **EHV networks** (P2 recommendations class E) N-1-1 redundancy of 2/3 group demand immediately. Asset rating will therefore be derated to 2/3 of their original ratings.

The analysis to map NGED archetypes to the GB model can then be used to determine how many networks in the GB would be experiencing outages in this case.

BESS profiles

A sensitivity analysis was undertaken to test the impact of alternative BESS operational behaviours on curtailment. In addition to the conservative 'full export at generation peak, full import at demand peak' assumption from Stage 1, alternative operation modes were modelled, including load shifting and partial export strategies. Battery profiles were established for two categories:

In the project, LV-connected domestic batteries were modelled as household load-shifting devices rather than as grid-scale assets. Their behaviour was aligned with residential demand patterns, charging at night when demand is low and discharging in the evening peak (typically 4–8pm) to reduce household load on the network.

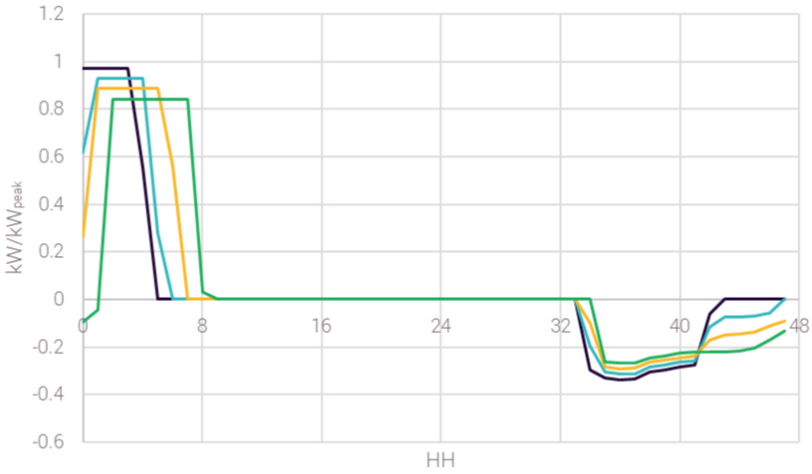


Figure 13: Domestic battery load profiles

In these profiles, batteries reduce demand (shown as negative load) during peak periods and recharge (positive load) overnight. Seasonal differences were captured by extending the evening discharge period in summer, reflecting longer daylight hours and a more prolonged evening demand tail.

Intermediate seasonal profiles (cool and warm) were generated by interpolating between winter and summer, but within each season a single representative profile was sufficient since battery operation consistently reflected household load-shifting behaviour.

Grid-scale batteries were modelled using 48 half-hourly profiles developed in line with the seasonal generation profiles used elsewhere in the Whole System Thinking project. Baringa provided average hourly dispatch data for around 75 large batteries (totalling 3,766 MW under the 2023 Net Zero High scenario), which EA Technology analysed to establish typical daily behaviour. From this dataset, three representative days were extracted: one dominated by charging (highest demand), one dominated by discharging (highest generation), and one showing average behaviour. These representative profiles were then applied for each season within Transform™ ensuring consistency with the approach used for other technologies.

The modelling reflected an economic dispatch assumption, agreed with NGED: on days with high renewable generation, grid-scale batteries are more likely to be charging, while on high demand days they are more likely to be discharging. This inverted the logic applied to renewable generation profiles, where maximum generation days increase export, by instead linking battery charging to periods of high renewable output and discharging to periods of high demand.

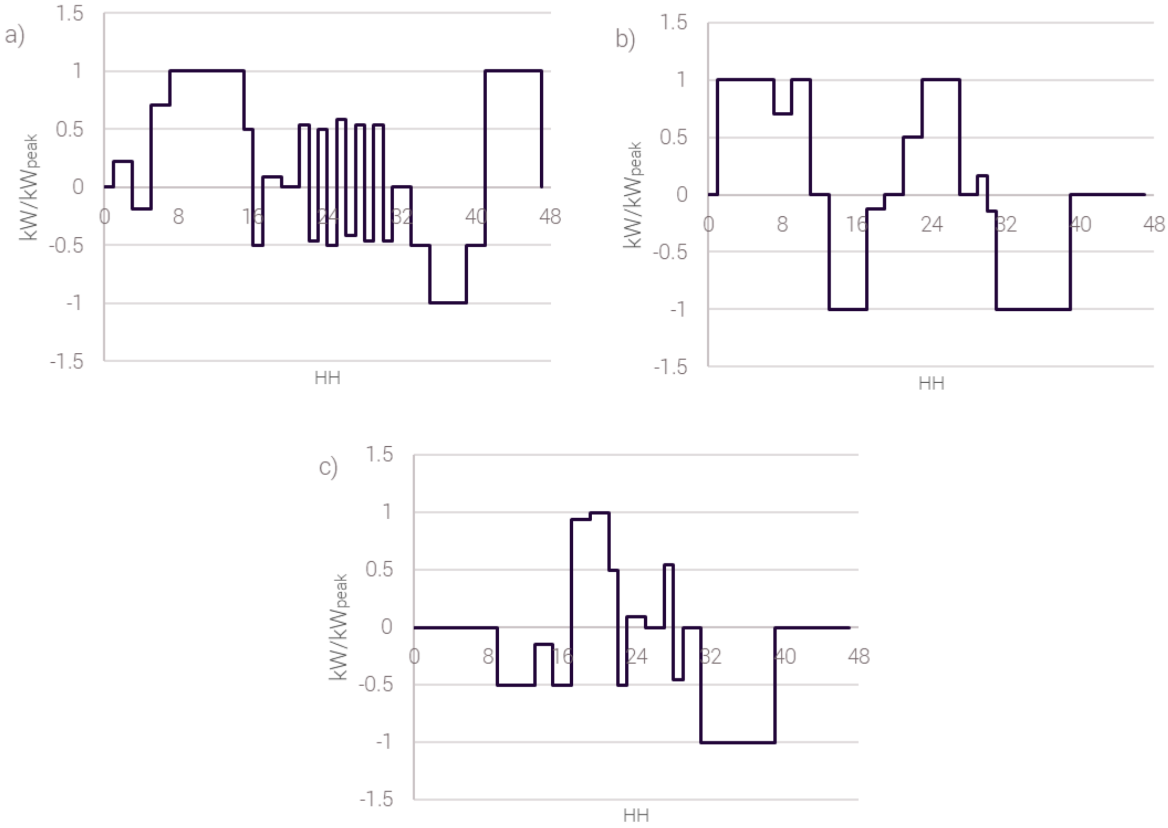
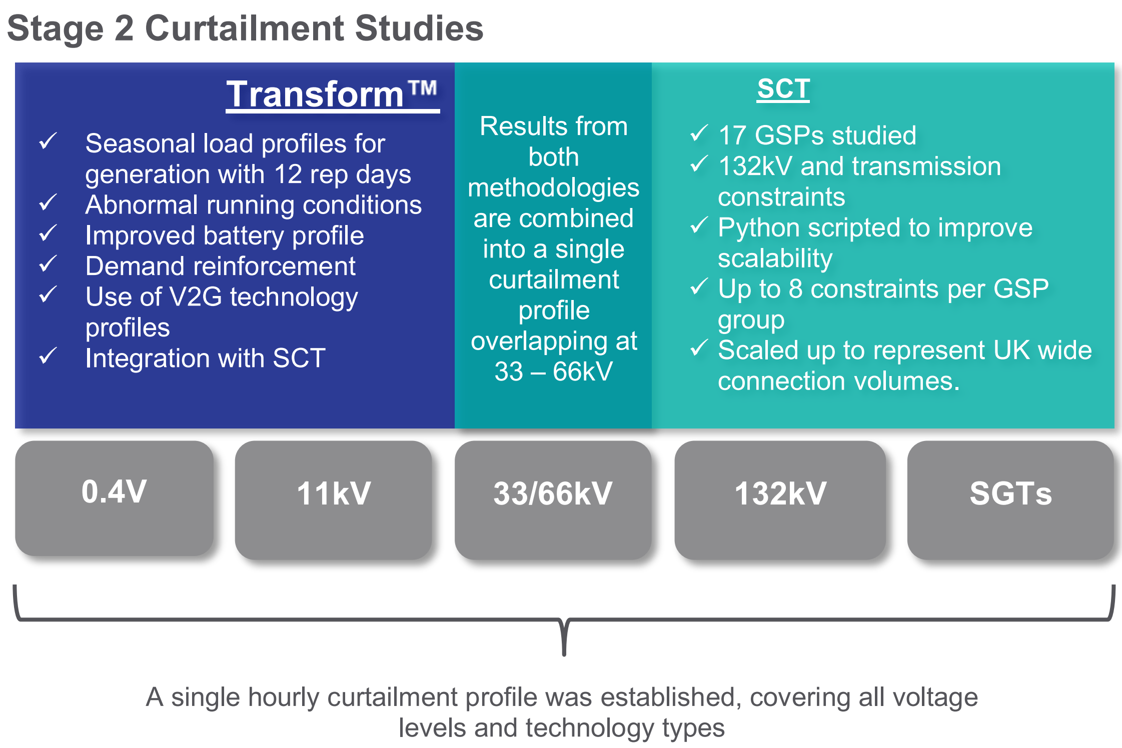


Figure 14: Grid-scale battery load profiles for the three winter representative days. Profiles for Intermediate Cool, Intermediate Warm and Summer can be found in the report a) peak generation day, b) average day, c) peak demand day

132kV network modelling using the Simple Curtailment Tool (SCT)

Following Stage 1, the Simple Curtailment Tool (SCT) was rebuilt from an Excel workbook into a Python application capable of evaluating up to ten simultaneous constraints per GSP with generator-specific sensitivity factors. Stage 2 then applied this enhanced tool across 17 NGED GSPs chosen to reflect a range of network demographics and technology mixes. To better reflect the reality of connection queues, a Monte Carlo approach was introduced to simulate attrition on a per-generator basis, with 0%, 25%, 50% and 75% outcomes sampled independently to produce probabilistic curtailment. Scenario years were aligned to typical queue outcomes: 2023 considered connected assets only (no attrition), 2028 assumed 75% attrition (25% progress to connection), and 2034 assumed 50% attrition, consistent with the current understanding that most applications do not materialise. The Python SCT produced half-hourly curtailment by technology (solar, wind, batteries, other), capturing interactions among multiple binding constraints that may include upstream transmission influences and downstream 33 kV/11 kV effects via the applied sensitivity factors. Because the SCT evaluates assets connected at 11 kV, 33 kV and 132 kV, its outputs were carefully coordinated to ensure that the final 132 kV curtailment reflected only residual curtailment at that level.

To avoid double counting at the EHV/HV–132 kV boundary, Transform™'s parametric curtailment results for EHV/HV were first mapped to each NGED GSP using rural/urban archetype assignments derived from the BSPs they feed; the resulting percentage curtailment for 11 kV and 33 kV assets was then removed from the SCT totals before any scaling. GB-wide scaling of the 132 kV results proceeded by allocating each of the 17 NGED GSPs to installed-capacity bands and using Embedded Capacity Register data from other DNOs (NPg, SSEN, SPEN, UKPN) to establish the GB distribution of GSPs across those bands. For every half hour and technology, the SCT curtailment observed in NGED was weighted up or down according to whether each capacity band was under- or over-represented in the NGED sample relative to GB (for example, bands comprising 18% of NGED's sample but only 9% of GB were scaled down). The weighted half-hourly contributions across all bands were then proportionally summed to represent 100% of the GB 132 kV network, yielding a single GB-average percentage curtailment series for 132 kV that is fully consistent with Transform™'s archetype-based EHV/HV results.



Stage 2 Curtailment Studies

Transform™

- ✓ Seasonal load profiles for generation with 12 rep days
- ✓ Abnormal running conditions
- ✓ Improved battery profile
- ✓ Demand reinforcement
- ✓ Use of V2G technology profiles
- ✓ Integration with SCT

Results from both methodologies are combined into a single curtailment profile overlapping at 33 – 66kV

SCT

- ✓ 17 GSPs studied
- ✓ 132kV and transmission constraints
- ✓ Python scripted to improve scalability
- ✓ Up to 8 constraints per GSP group
- ✓ Scaled up to represent UK wide connection volumes.

0.4V | **11kV** | **33/66kV** | **132kV** | **SGTs**

A single hourly curtailment profile was established, covering all voltage levels and technology types

Figure 15: Stage 2 Curtailment studies

Stage 2 Curtailment profiles

Comparison between Stage 1 and Stage 2 results

Compared on an annual basis, Stage 2 reports materially higher curtailed energy than Stage 1 in every study year (2023, 2028 and 2034). Stage 1's annual totals are almost entirely driven by summer PV constraints and therefore omit winter and shoulder-season effects, keeping the yearly

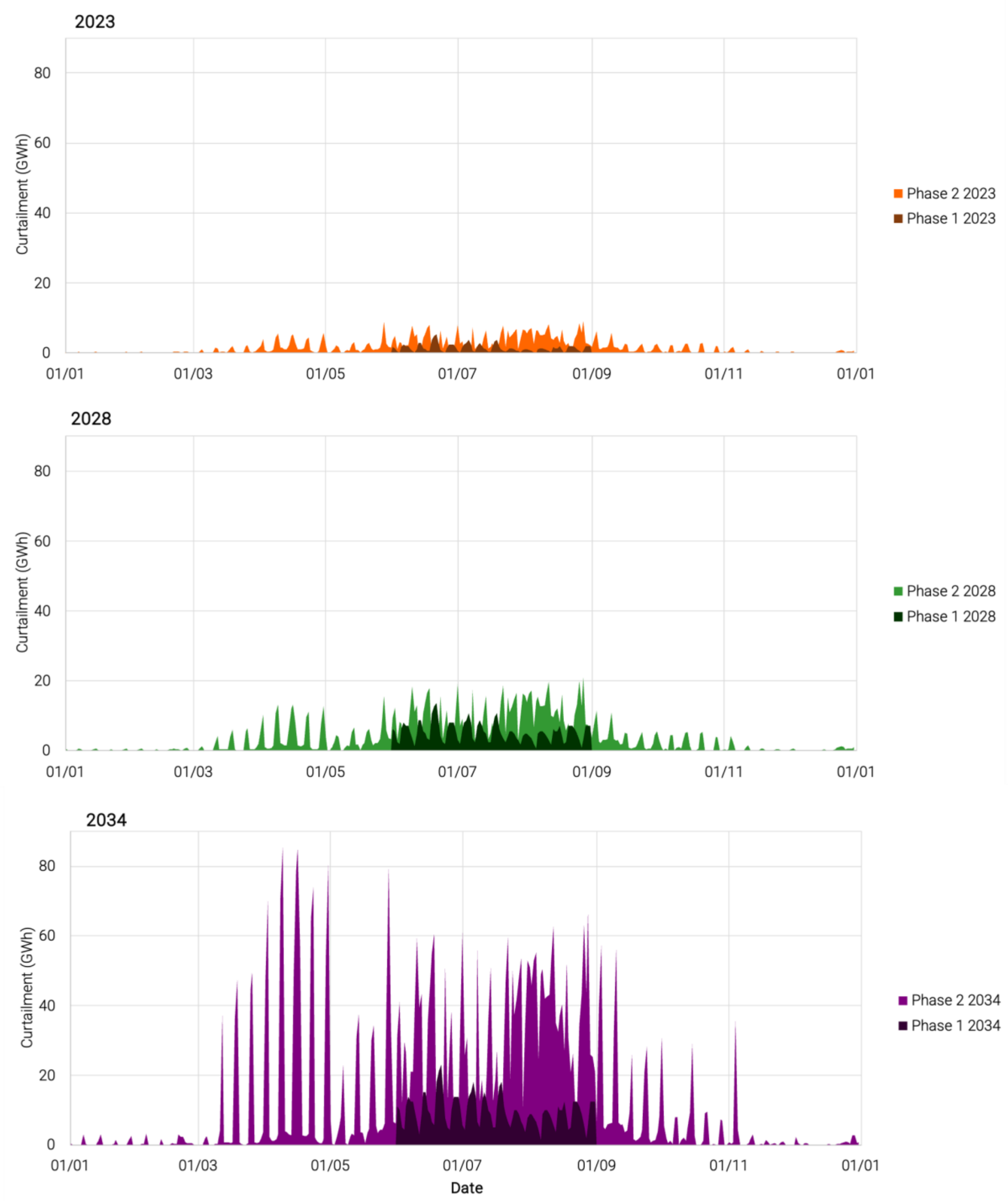


Figure 16: Total daily curtailment on the LV-EHV networks from the Transform curtailment analysis comparing Stage 1 and Stage 2 results

figures lower. Stage 2 shows curtailment occurring in all seasons, which both raises the annual totals and spreads them more evenly across the year (a larger share now falls outside summer). Importantly, Stage 2’s annual curtailment remains above Stage 1’s even after accounting for demand-led reinforcement that increases asset ratings, indicating generation-driven export limits are the dominant driver of yearly curtailment.

Curtailment by generation technology type

Curtailment behaviour shifts markedly by technology over the study period. In 2023, around 57% of curtailed energy is attributed to “other” dispatchable plant (gas, oil, biomass), largely at higher voltages (e.g. 132 kV) and likely overstated by the SCT’s simplifying assumption that these units always contribute maximum output; in practice they dispatch economically and would not present year-round curtailment exposure. By 2034 the picture reverses, with roughly 57% of all curtailment falling on solar as PV penetration rises, and curtailment is observed across every season. Solar, wind and BESS each see increasing curtailment through 2023–2034, while “other” increases to 2028 then declines by 2034 in line with a shrinking gas share. Wind records the lowest curtailment in all years because only distribution-connected onshore wind is modelled, top-down transmission constraints are excluded, and FES 2023 predates policy changes expected to accelerate onshore wind uptake. Total curtailed energy reaches about 8.5 TWh in 2034 (just under 3.2 million, ~11% of UK homes).

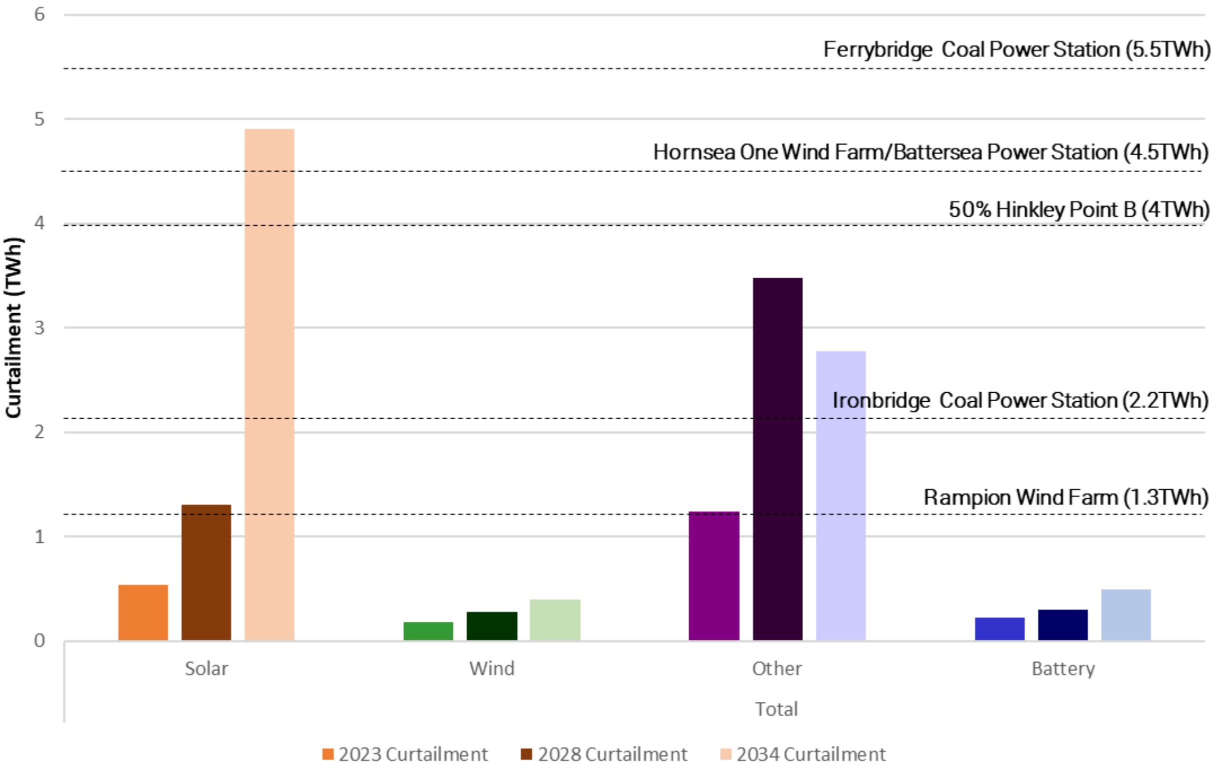


Figure 17: Total annual curtailment in GWh for the four generator categories in 2023, 2028 and 2034. Curtailment volumes are compared to the generation capacity of some UK based power stations.

Voltage level curtailment behaviour

Curtailment varies materially by voltage level and shifts over time as the connected generation mix changes. In 2023 and 2028 most curtailment occurs at 132 kV (around 73% and 76% of the total respectively), reflecting the prevalence of larger plant (gas, some wind and BESS) at that level and the way the Simple Curtailment Tool (SCT) assumes constant availability from BESS & ‘other’ sources. By 2034 the balance flips: the LV network accounts for about half of all curtailment as domestic and small-scale solar dominates export-driven voltage rise on feeders. LV curtailment is concentrated in summer and is overwhelmingly voltage-headroom limited (≈80% of constraints), with assets modelled near the top of the voltage window (taps high) to prioritise demand security. Even where demand-driven reinforcement increases LV asset ratings, generation-driven curtailment still grows year-on-year, indicating a need for measures that explicitly increase export headroom (e.g., tap policy changes, voltage optimisation, targeted reinforcement). HV records the lowest curtailment across the study horizon owing to larger headroom (higher ratings, assumed OLTC keeping operation mid-band) and less DG density; however, the parametric approach may underestimate local hotspots. EHV sits between HV and 132 kV: while summer curtailment remains highest, a more diverse mix (wind, gas, BESS) drives appreciable curtailment in colder seasons too. At 132 kV, curtailment is more evenly spread through the year because the generation mix is less solar dominated; note that assuming constant availability for “other” plant and BESS likely overstates both availability and therefore curtailment at this level.

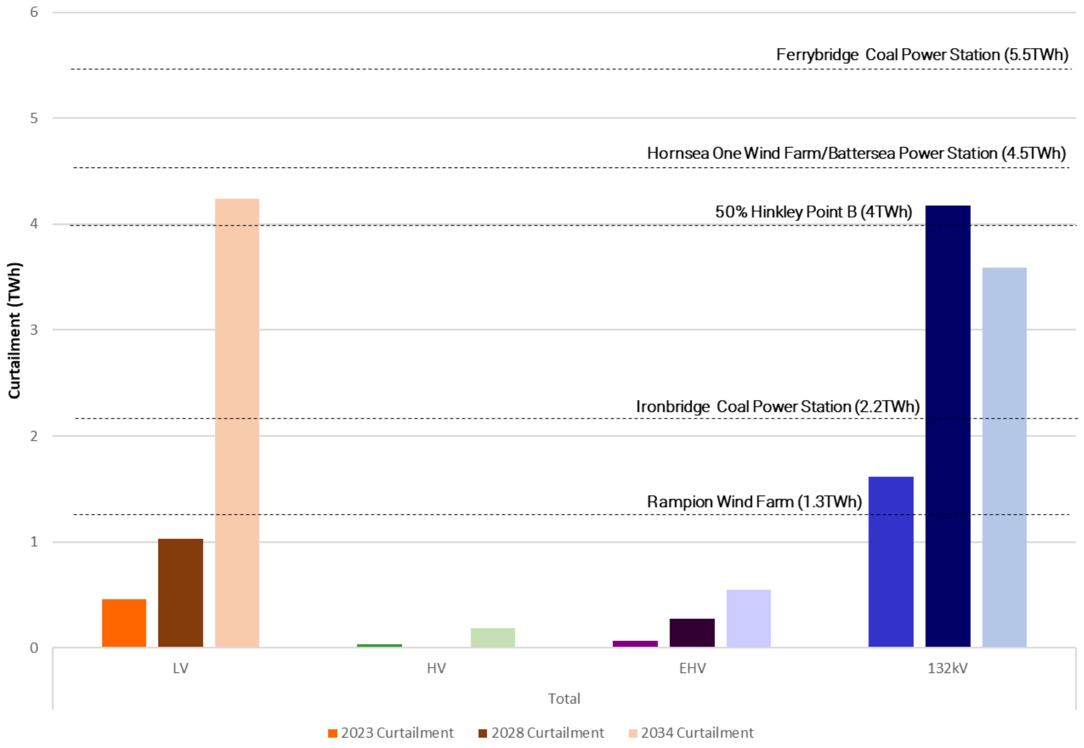


Figure 18: Total annual curtailment in GWh for the four voltage levels in 2023, 2028 and 2034. Curtailment volumes are compared to the generation capacity of some UK based power stations

Battery Sensitivity

To compare the updated battery profiles against those used previously, two Transform™ runs were compared: the original profile and an updated set derived from market-based BESS behaviour (from Baringa), which shows batteries exporting at price peaks and varying across seasons. With the updated profiles, total curtailment falls in 2023 because constant daytime battery export on peak-generation days is removed. By 2034, however, the gap versus the original narrows: batteries exporting at evening peaks displace other technologies, raising curtailment for solar and "other" generators during those hours, while wind and BESS curtailment itself declines due to more off-summer generation and variable daily patterns. Impacts differ by voltage: LV changes are negligible (very little connected BESS; domestic units largely behind-the-meter), whereas HV/EHV are more sensitive given a more diverse mix. Interactions with reinforcement also matter in the original set-up, BESS acted as additional demand outside peak-generation days, prompting earlier/larger demand-led uprates that reduced curtailment by 2034; the updated profiles reduce peak demand, delay some uprates, and help explain a higher HV curtailment delta in 2034. Overall, the exercise shows curtailment is highly sensitive to realistic BESS operation and to the coupling between dispatch behaviour and reinforcement triggers.

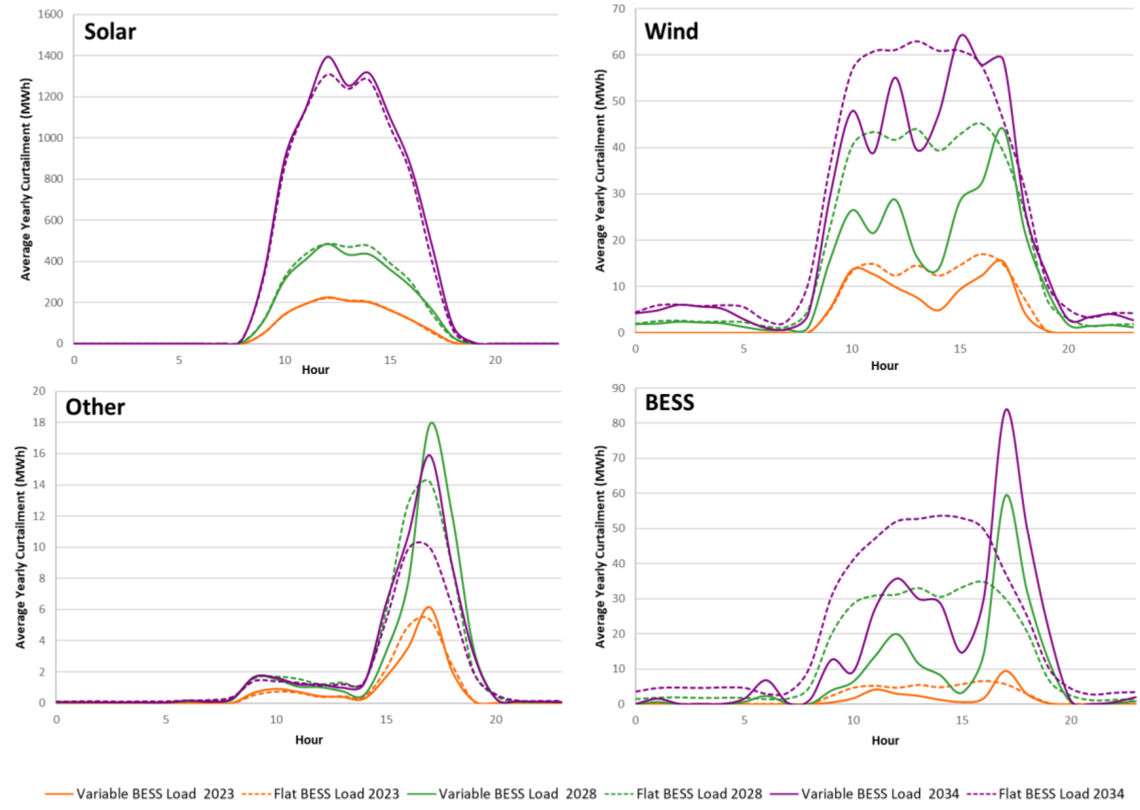


Figure 19: Average curtailment at each hour of the day for the different generator types in 2023, 2028 and 2034, new variable BESS load profile model (dashed lines) and previous flat BESS load profile model (solid lines)

Stage 2: Network Modelling Output

- Stage 2 Curtailment Modelling

Power Market Modelling

Similarly to Stage 1, PLEXOS was used by Baringa to simulate the wholesale market. Exploratory Data Analysis was used to explore the main drivers of curtailment, PLEXOS modelling was used to forecast wholesale market effects (including a voltage and volume-based sensitivity), and a quantitative assessment of ancillary service impact was undertaken.

Exploratory Data Analysis to determine the main drivers of curtailment

Curtailment projections were built by EA Technology using the Transform™ network model and NGED's Simple Curtailment Tool, produced hourly curtailment/generation datasets for 2023, 2028 and 2034 across LV, HV, EHV and 132 kV, and for five technologies (BESS, gas, PV, wind, V2G). In the market modelling, these curtailments are treated as additional fixed demand at the transmission–distribution boundary. Given ~0.9 million rows, an exploratory data analysis examined correlations/cross-correlations and applied decision-tree feature importance to identify causal patterns. Methodologically, this surfaced strong PV–curtailment coupling at LV (≈99% of LV curtailment), wind/PV effects at 132 kV, and revealed that BESS utilisation is a key driver of 132 kV curtailment, an insight not obvious from simple EDA alone. The analysis also noted apparent propagation of LV issues to HV/EHV (with a caution that some relationships could be statistical rather than causal). These findings informed where releasing headroom would most relieve curtailment pressure through the horizon.

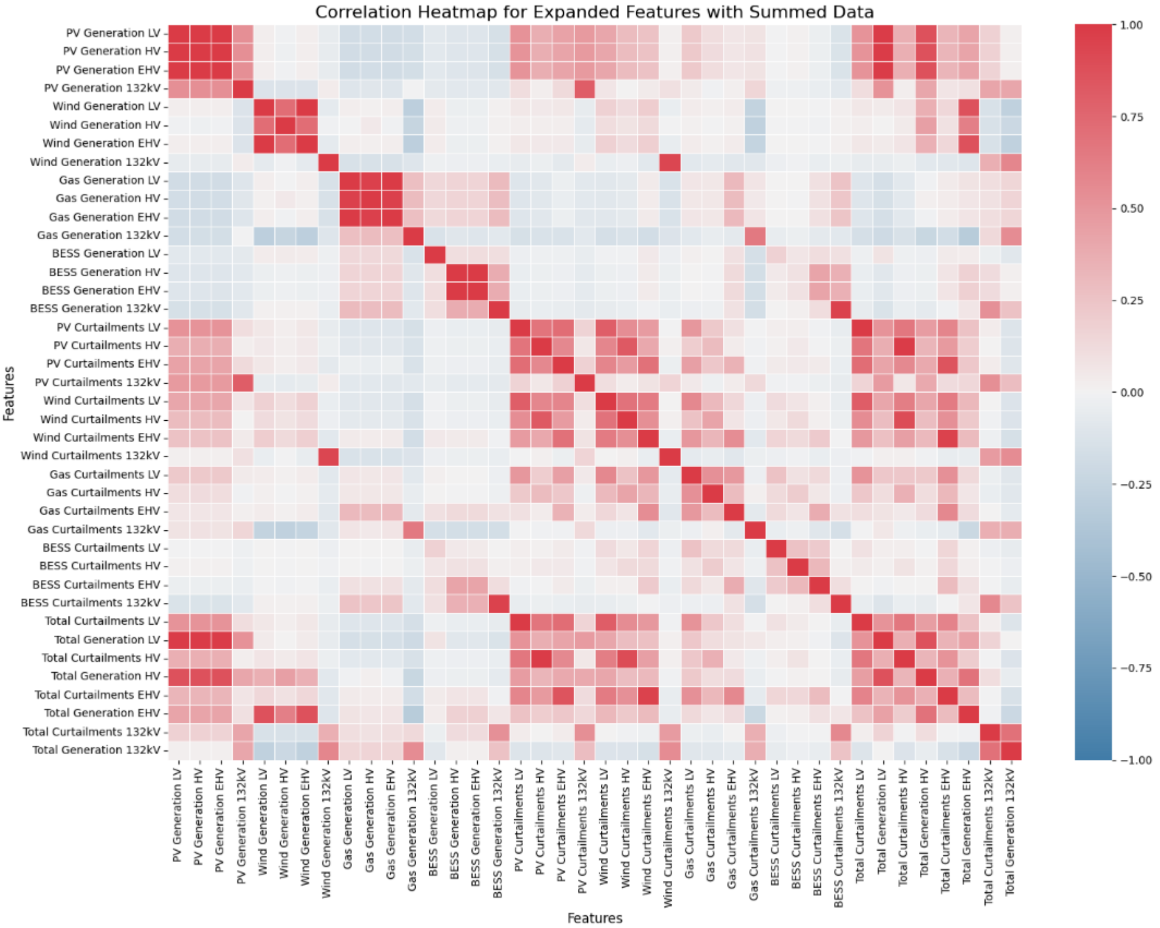


Figure 20: Cross-correlation between all features

Market Modelling - Voltage sensitivity

The GB-wide power market model (Baringa NZH) compares a “counterfactual” with no distribution curtailment to a “curtailment” case in which curtailed volumes are imposed as extra load. Curtailments are disaggregated by voltage level and technology to align with the Best-View dataset, then re-aggregated to the distribution total and passed to the bulk system. Benefits from releasing headroom are measured as System Cost Impact (wholesale cost delta) plus System Carbon Cost Impact (UK ETS/taxes delta). For voltage sensitivity, curtailments by each voltage tier were applied in isolation to attribute impacts. Results show 132 kV delivers the largest accumulated benefit (~53%) but declines after 2028, while LV benefits grow almost linearly and reach ~37% by 2034; HV/EHV contribute materially less to carbon and cost outcomes. Assumptions include NZH trajectories for capacity/carbon prices and linear interpolation between the three study years.

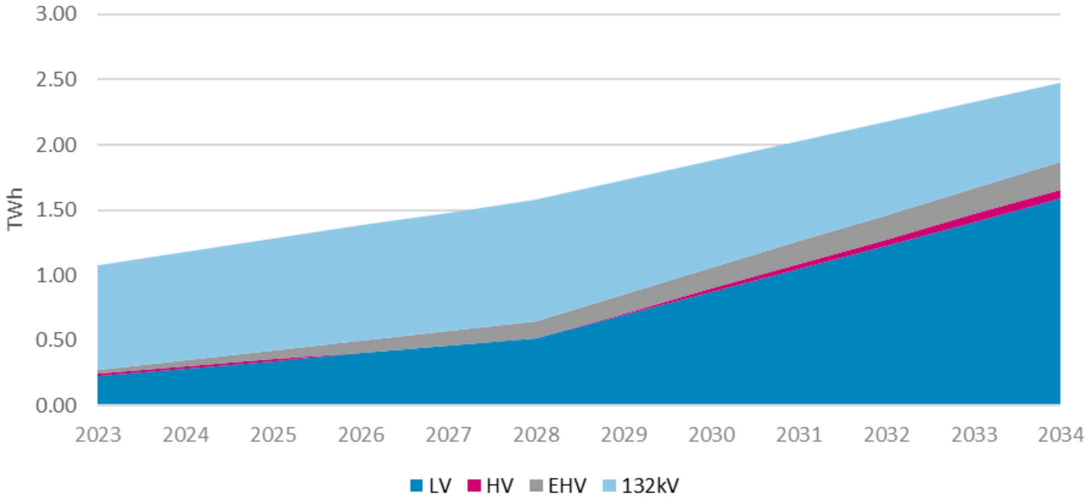


Figure 22: Curtailment viewed per voltage level under the 'best view' case

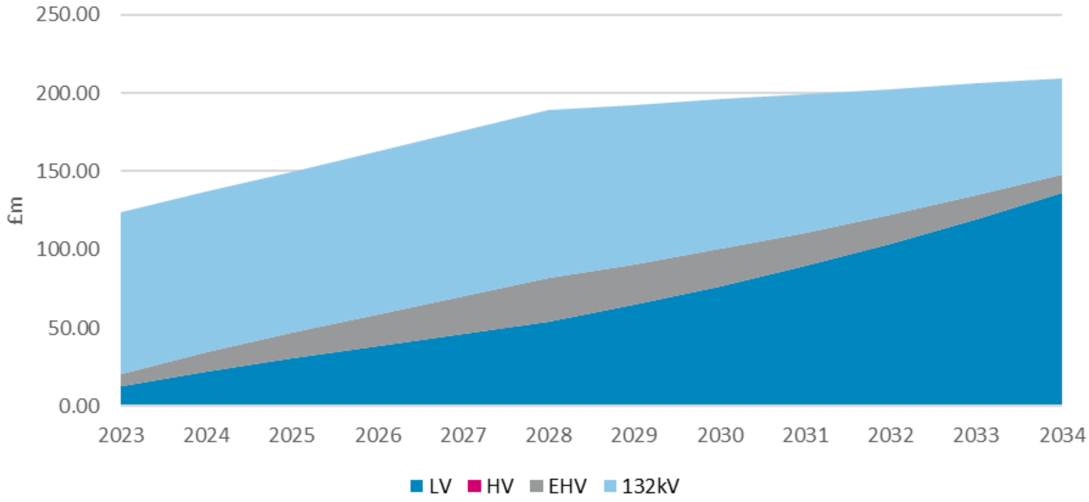


Figure 21: Cost impact per voltage level under the 'best view' case

Market Modelling - Volume sensitivity

To test volume sensitivity, the team scaled Best-View curtailments (e.g., 20%–180%) holding all other NZH assumptions constant, then recomputed wholesale and carbon impacts. This isolates the effect of different curtailment magnitudes on system outcomes. Across the horizon, projected curtailments span ~4.17–36.33 TWh, illustrated in Figure 23; corresponding total system benefits from releasing headroom range from ~£486 m (low curtailment) up to ~£3.88 bn (high curtailment) illustrated in Figure 24, with the Best-View around £2.1–£2.5 bn. The approach assumes curtailments behave as fixed load, that NZH price/dispatch dynamics capture marginal cost and emissions responses, and that interpolation between 2023/2028/2034 reasonably represents intervening years.

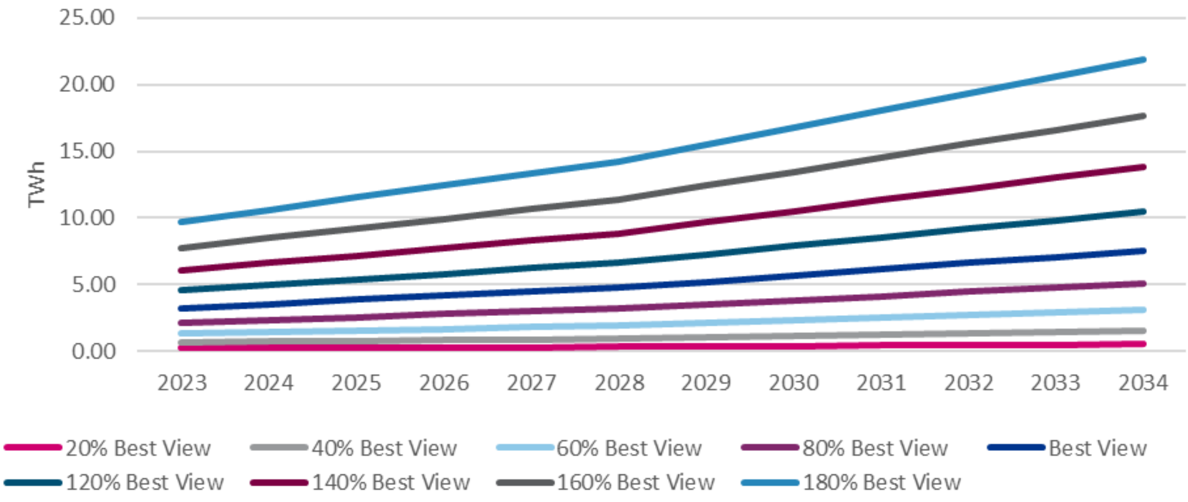


Figure 23: Projected curtailments for different values of Best-View

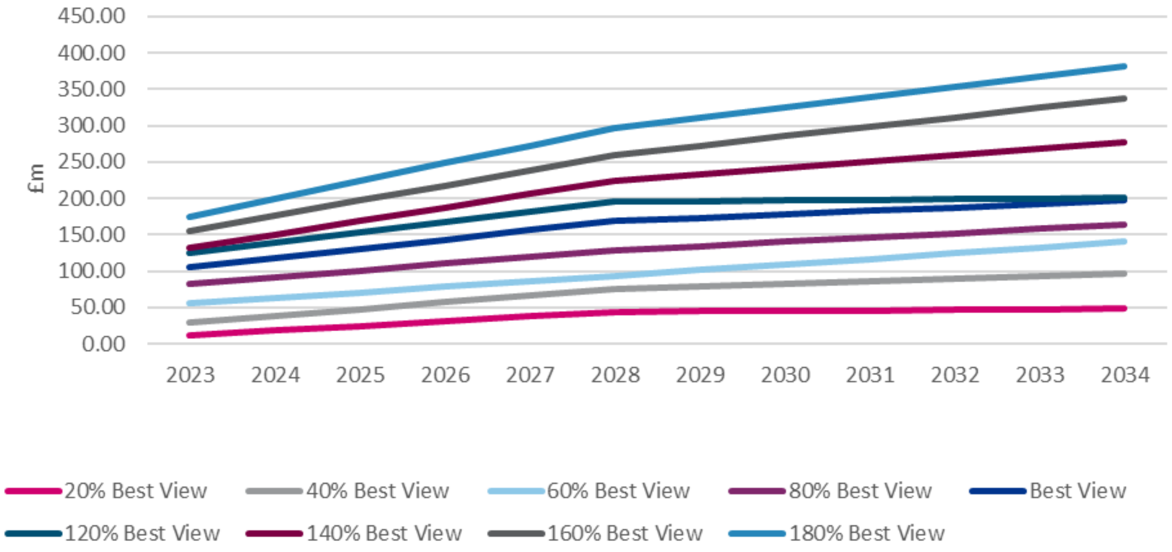


Figure 24: Projected system cost impact for different values of Best-View

This sensitivity work provided insight to the coupling between the overall volume of distribution curtailment, and the wholesale impact. When plotted against each other, a consistent value of around £100/MWh was derived, with a linear relation, illustrated in Figure 25. This is a key learning of the project and has formed the basis of our DSO benefit reporting for schemes aimed at reducing curtailment.

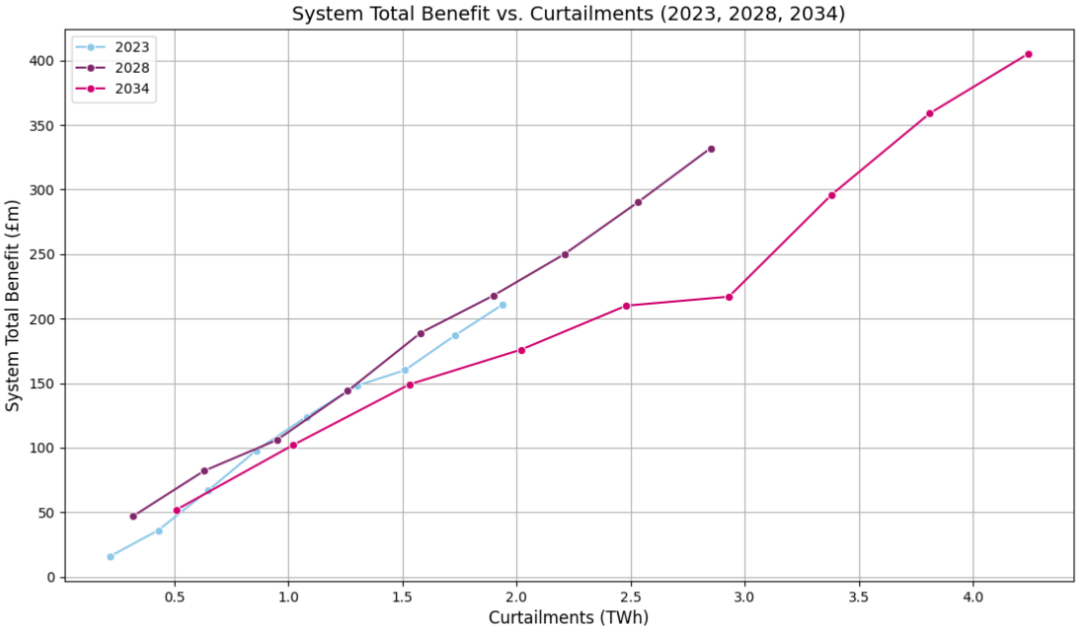


Figure 25: Annual relationship between curtailment and system total benefit

Balancing services - Analysis of balancing services

The study assessed how headroom constraints limit DER participation in NESO services, drawing on an overview of current/future procurement (notably the Enduring Auction Capability, EAC) and the role of the Balancing Mechanism (BM). The work firstly assessed the historic spend on ancillary services and used forecasted balancing costs to determine the scale of cost which could be affected by headroom availability. Figure 26 presents the forecasted cost of NESO balancing, published by NESO in their FES publication. Costs for 2030/31 are not published, and from then onwards projections reflect uncertainty linked to network build. Aside from ‘Falling Short’, the trend predicts an overall growth in balancing costs.

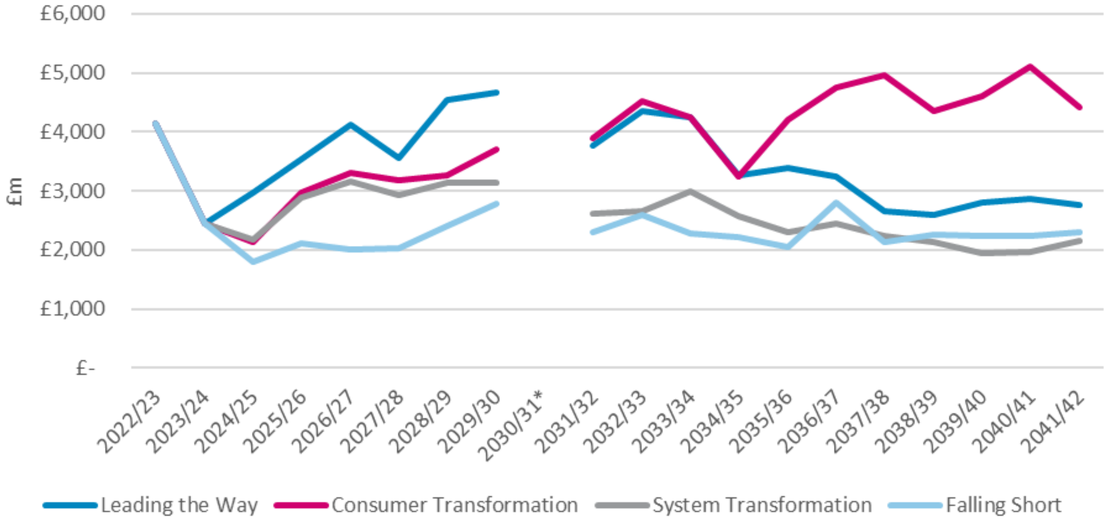


Figure 26: Cost of balancing NESO projections

To determine how the availability of distribution connected assets may influence these costs, Baringa assessed the connection voltage of assets bidding for each service between 02-Nov-23 and 03-Mar-24. Figure 27 presents a summary of this, indicating the extent to which each service is met by distribution connected assets.

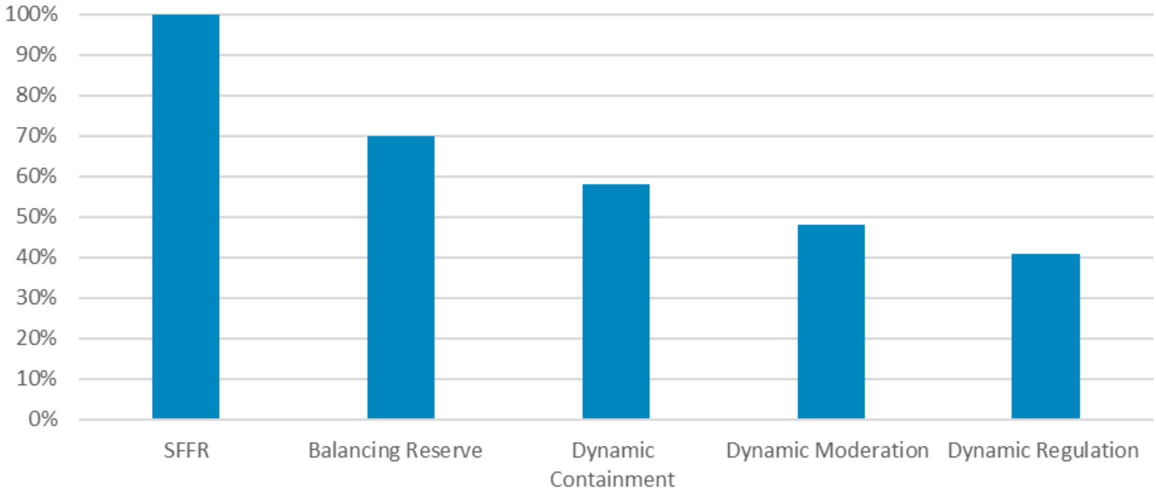


Figure 27: Summary of proportion of service providers who are distribution connected

Using historic stacks, Baringa simulated the removal of 1–25% of distribution bids to gauge price impacts under a “best-case” assumption of sufficient market depth to move up the stack; per-unit cost increases were generally small. The Static Firm Frequency Response (SFFR) service returned the greatest average increase in price due to removing distribution assets and was also the service where 100% of bids were from distribution connected assets.

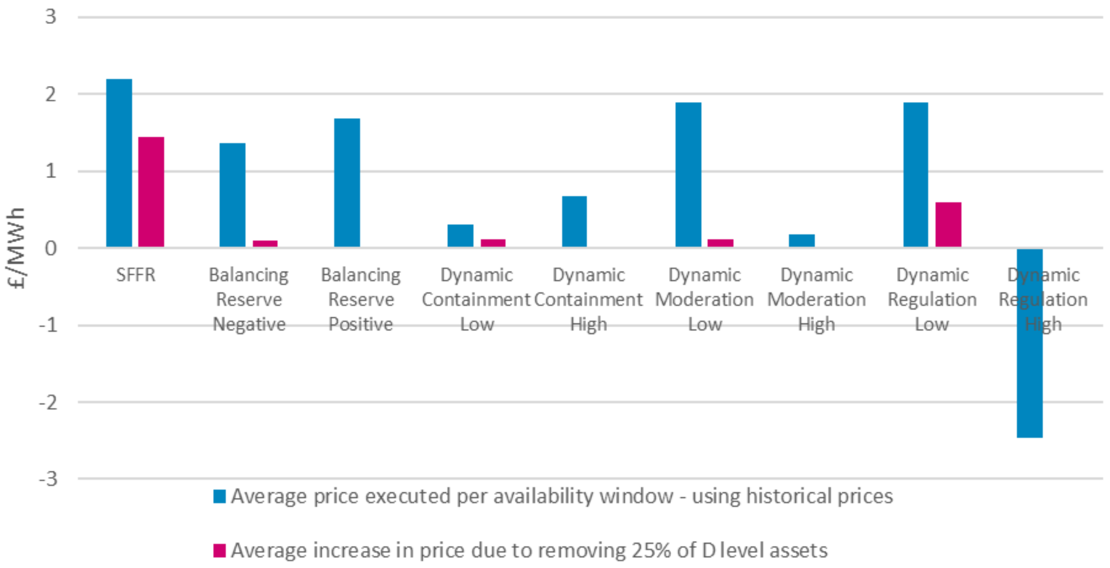
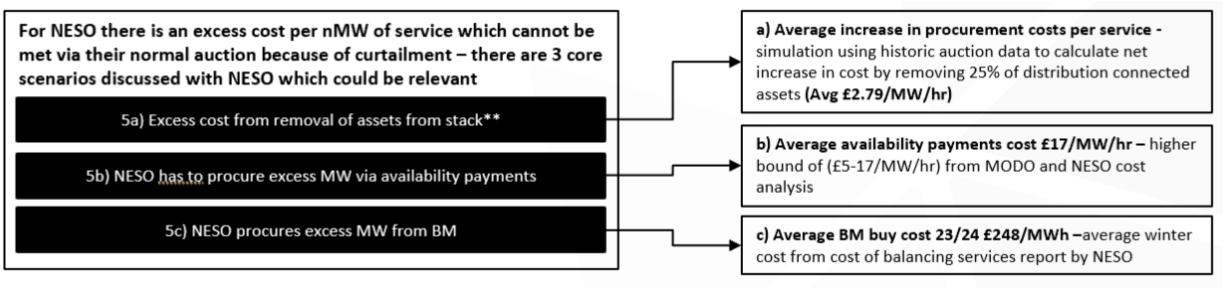


Figure 28: Indication of the increase in costs because of removing 25% of distribution assets

However, operational realities can force alternative responses, so three practical scenarios were defined with NESO, (a) auction depth covers the gap, (b) pre-secured excess availability, (5) last-minute BM action, highlighting that outcomes depend on data visibility of day-ahead curtailment and service need.



For NESO there is an excess cost per nMW of service which cannot be met via their normal auction because of curtailment – there are 3 core scenarios discussed with NESO which could be relevant

5a) Excess cost from removal of assets from stack**

5b) NESO has to procure excess MW via availability payments

5c) NESO procures excess MW from BM

a) Average increase in procurement costs per service - simulation using historic auction data to calculate net increase in cost by removing 25% of distribution connected assets **(Avg £2.79/MW/hr)**

b) Average availability payments cost £17/MW/hr – higher bound of (£5-17/MW/hr) from MODO and NESO cost analysis

c) Average BM buy cost 23/24 £248/MWh –average winter cost from cost of balancing services report by NESO

Figure 29: Three scenarios discussed with NESO which could occur in cases of unavailability from distribution connected Balancing Service providers

Balancing services - Methodology establishment

Given limited visibility to bottom-up service-specific substitutions, a top-down method was adopted. EATL curtailment volumes were mapped to the share of NESO balancing requirements potentially affected, and historic costs were used to parameterise two bounding cases: average balancing cost across all methods (£97/MWh) versus BM-only cost (£114/MWh). Scenario 1 adds BM costs on top of baseline balancing when curtailment bites; Scenario 2 assumes the baseline is displaced and only BM costs are incurred, then a blended case was used to represent likely reality. The method explicitly recognises that using Balancing Services data alone would under-scope NESO costs (because BM/bilaterals also matter) and that robust bottom-up estimates would require assumptions the project could not justify without better data sharing.

- **Scenario 1 (Worst Case):** NESO balancing actions are nullified by DNO constraint. Likely to occur where curtailment notification is close to real-time and / or unpredictable and NESO has already procured service from a provider for which they then have to pay
- **Scenario 2 (Best Case):** Curtailed volume is procured at the average BM cost with pre-existing costs for curtailed volume negated. Reflective of the case where NESO could predict or anticipate a conflict and withdraw service payments.
- **Scenario 3 (Blended Case):** Costs reflect a mix of Scenarios 1 and 2. Realistic assumption based on industry progress in data sharing, flexibility co-ordination, transparency, and primacy rules. Presumes negligible primacy co-ordination in 2023/2024 as NESO would be unaware of whether flex providers are within an ANM zone. Presume foresight by NESO to enable Scenario 2 remains low in 2028/2029 but grows to 50% in 2034/2035.

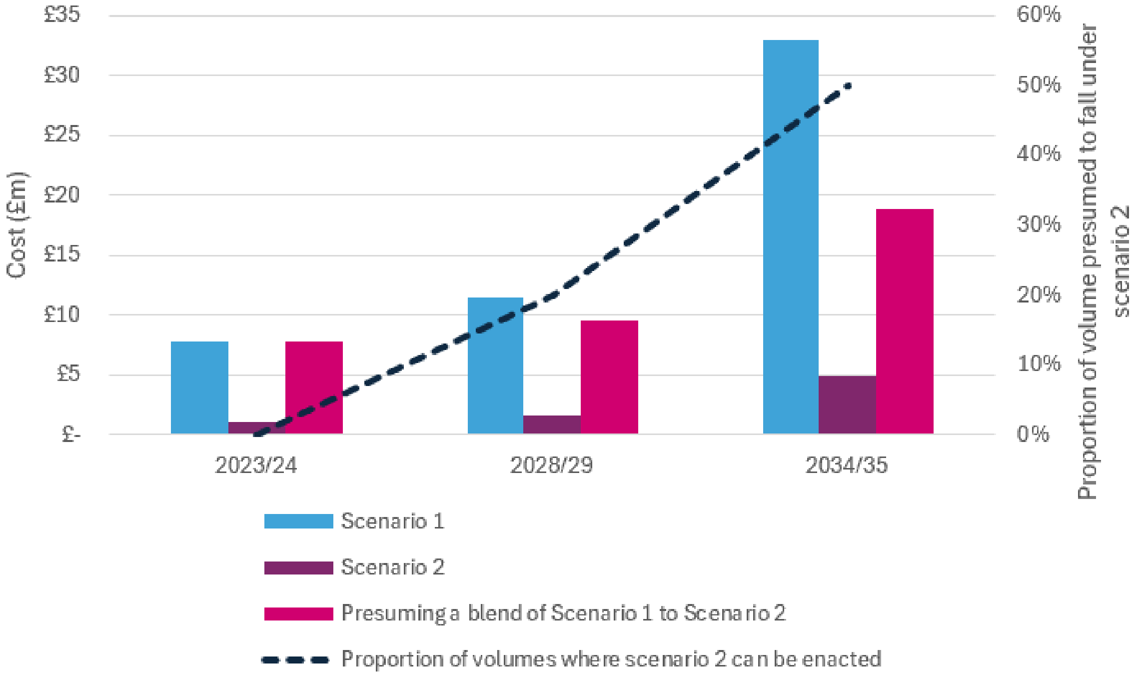


Figure 30: Indication of the proportion of each scenario assumed in the 'Blend' case and the costs of curtailment

Balancing services - Results

Under the auction-depth “best-case” (stack removal) test, simulated EAC products showed negligible per-unit price increases even when 25% of distribution bids were removed, but the three NESO scenarios indicate total costs could rise materially if last-minute BM actions are needed and curtailment is not visible day-ahead. Aggregated to the programme scope, releasing distribution headroom is estimated to reduce balancing-related costs by ~£350 m over the horizon by enabling more DER participation and lowering reliance on expensive constraint-driven actions.

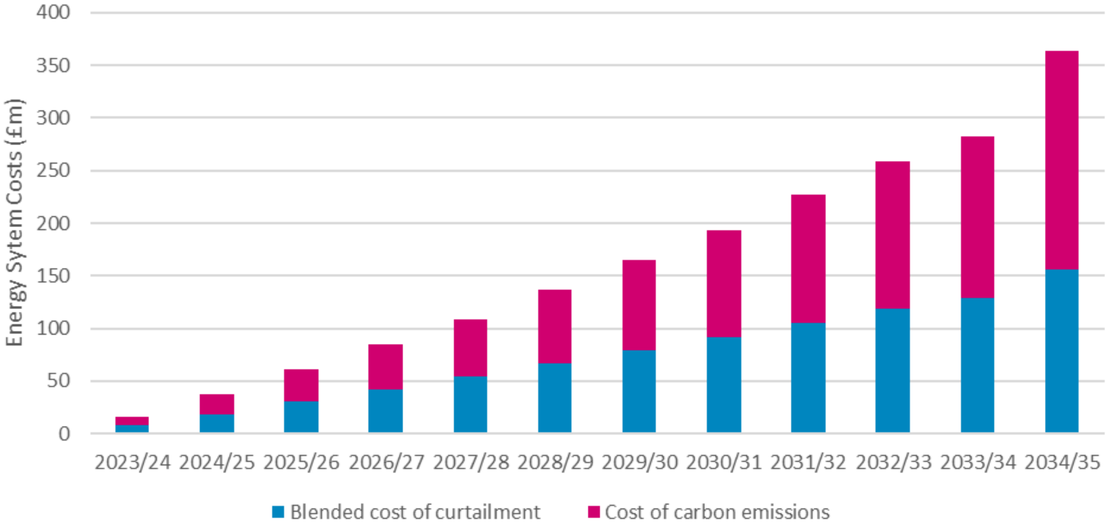


Figure 31: Cumulative cost of curtailment and carbon emissions cost for ancillary services

Conclusions and recommendations

Methodologically, the project demonstrated a consistent framework linking detailed curtailment projections to GB-wide market and balancing outcomes, with clear attribution by voltage level and curtailment volume. The evidence shows the bulk of benefits accrue at 132 kV and LV (≈90% combined), with benefits shifting from 132 kV toward LV over time; system benefits span ~£0.5–3.9 bn depending on curtailment levels, with Best-View around £2–2.5 bn. Recommended next steps are to prioritise LV interventions as PV penetration grows, continue targeted action at 132 kV (mindful of its declining share post-2028), improve DSO–NESO data exchange on curtailment forecasts to avoid costly BM responses, and further investigate causal chains (e.g., LV-to-HV/EHV propagation; BESS interactions at 132 kV) to refine where releasing headroom yields the highest net benefit.

Stage 2: Power Market Modelling Output:

- Stage 2 Power Market Modelling

6. Performance Compared to Original Aims, Objectives and Success Criteria

Overall, the project achieved all of its objectives and success criteria. Details can be found below:

Table 12: Performance compared to project objectives

Objective	Status	Performance
Develop a methodology to calculate the whole system value of network headroom.	✓	During the project, a comprehensive methodology to calculate the whole system value of network headroom was established, refined, and published in project reports. Firstly, curtailment profiles for generators connected to the distribution network needs to be forecasted. This project used Transform™ and NGED's Simple Curtailment Tool, which output a single hourly profile disaggregated by technology type and voltage level. To consider the whole system cost effect, wholesale market costs were calculated using PLEXOS, and ancillary service costs were established through forecasting the volume of ancillary services unavailable to NESO due to network constraints. Overall, this methodology was able to provide a value of network headroom to the wider energy system.
Produce representative headroom archetypes that demonstrate where headroom provides value to the energy system	✓	Archetypal networks were established in EA Technology's Transform™ modelling, which applied the 2023 FES scenarios to forecast the likely connection of low carbon technologies. 132kV and SGT constraints were considered in NGED's SCT modelling, studying 17 Grid Supply Points which represented a variety of dominant generators.
Quantitatively understand what parts of the network added headroom has the most significant financial benefit to the whole energy system. This will be discussed in terms of voltage level, types of connected generation, and types of connected demand	✓	132kV delivers the highest accumulated benefit over the study horizon, contributing 53% (£1,125m) of the total value but its contribution declines steadily over time. Benefits from LV increase almost linearly over time, eventually accounting for 37% (£795m) of the total accumulated value by 2034, underscoring its growing importance in delivering system benefits. 132kV curtailments drive most avoided emissions, accounting for 69% of the total (1.34Mt). Its contribution also declines steadily over time. Avoided emissions at LV grow steadily throughout the analysis horizon, representing 27% of the total avoided emissions by 2034. EHV and HV play minimal roles in carbon emissions reduction.
Understand the constituent parts of customer bills which are most	✓	Added headroom lowers customer bills through three pass-through components, dominated by

Objective	Status	Performance
impacted by added headroom, i.e. wholesale price savings, balancing market savings, carbon savings		wholesale price savings. By avoiding curtailment, more low-marginal-cost renewables clear and displace thermal plant, driving an accumulated wholesale market benefit of about £1,931m in the Best-View case (2023–2034). Carbon costs also fall as emissions drop, worth ~£213m across the period (valued via UK ETS in the model). Fewer constraints also let more DER provide security and frequency services, reducing NESO balancing costs by ~£350m, which suppliers recover from consumers, i.e. a second, material bill impact. Combining wholesale and carbon gives ~£2,144m of system benefit, and ~£2.5bn once balancing is included, so the indicative split is ~77% wholesale, ~14% balancing, ~9% carbon.
Collated information to give values for £/MWh and CO2/MWh headroom whole system value, which will vary depending on archetype grouping	✓	The project successfully met this objective by collating curtailment and market modelling outputs into quantified whole-system values expressed in £/MWh and CO_2/MWh. Stage 2 analysis demonstrated an average headroom benefit of £100/MWh and 15–20 kg CO_2/MWh, with values varying by voltage level and feeder archetype grouping, thereby evidencing how different network archetypes contribute distinct financial and carbon benefits.

Table 13: Status of project success criteria

Success Criteria	Achieved	Performance
Stage 1 Success Criteria		
A successful expert workshop is held, with attendance from National Grid DSO, NESO, and project partners. The outcomes of the workshop have successfully directed the project towards maximum value.	✓	Following the October kick-off workshop, the following assumptions were made to the modelling methodology: Demand reinforcement should be excluded from Stage 1 of the work. This was chosen to calculate an upper bound for curtailment benefit. The chosen study years should include 2023 as a baseline year, and the latest study year should be 2034 to be in line with BAU network planning horizons. After the end of stage 1 workshop in February, several changes were made to the original project scope, to direct the project towards maximum value. It was acknowledged in Stage 1 that the network curtailment modelling which forecasted generation curtailment volumes and profile had several assumptions which did not hold up to scrutiny. There is

Success Criteria	Achieved	Performance
		no known methodology to assess curtailment at a system-wide scale, as such the revised project direction for Stage 2 focuses on establishing 'cost-curves' to calculate the scale of expected benefit across a range of curtailment volumes. Further information on this change is detailed in the following section.
A comprehensive methodology to understand the value of network headroom is produced. This should be completed in collaboration with National Grid, Baringa and EA Technology LTD.	✓	Stage 1 established a methodology to forecast the value of network headroom across UK DNOs. Collaboration between NGED, NESO and the project partners within Stage 1's workshop allowed for feedback on assumptions and the employed methodology. Specific detail on the methods used is captured in the Stage 1 reports accessible on the NGED website. National Grid - Headroom - Whole System Thinking.
A conceptual translation of headroom on generation, BESS, and demand is produced in Stage 1, which helps understand exactly how to model headroom availability.	✓	Specific details can be found in the End of Stage 1 report. https://www.nationalgrid.co.uk/downloads-view-reciteme/660492
An understanding of how the value network headroom availability differs according to voltage level, and according to time-base scenarios.	✓	EA Technology performed a sensitivity study using Transform™ and NGED's Simple Curtailment Tool. Further details can be found in the Stage 1 Network Modelling Report. https://www.nationalgrid.co.uk/downloads-view-reciteme/660491
Following detailed PLEXOS studies, understand how headroom availability changes the carbon intensity of the grid and consequently offers carbon savings.	✓	The emission which could be avoided through headroom relief is forecast to range between 0.7 Mt ('Network Curtailment' scenario) and nearly 5 Mt ('Maximum Constrained Generation' scenario) accumulatively from 2023 to 2034. This amount of carbon saving is broadly equivalent to the level could be achieved by 20 to 170 thousand electric vehicles over their lifetime. Further details can be found in the End of Stage 1 report.
Incorporate constraints based on a national view into PLEXOS to understand the proportion of available low	✓	Curtailment profiles for distribution connected generation assets were incorporated into PLEXOS within Stage 1.

Success Criteria	Achieved	Performance
carbon generation that is curtailed, which otherwise supports the merit order effect.		
Develop an understanding of how the proportion of renewable generation affects the wholesale price. During Stage 1, this will be at a national level with only qualitative consideration of whether demand and generation assets are connected to the distribution network or transmission network.	✓	A sensitivity study was performed in Stage 1. A more granular assessment producing cost curves illustrating the scale of impact at different volumes of renewable curtailment will be produced in Stage 2.
Provide an understanding of the scale of benefit increased distribution headroom may have in terms of £/MWh, and CO2/MWh. At Stage 1, this will explore what times of the year the benefit is largest.	✓	The accumulated system cost saving could range from ~£330m to ~£17bn between 2023 and 2034 (£27.5m to £1.4bn annually); this represents a saving of 0.2% to 7.0% of the total system cost by 2034. The carbon cost saving that could be achieved in each year is between £5m and £125m, making an impact on annual carbon cost at 0.2% (2023) to 40% (2034). This is equivalent to reducing the emission from 17,000 (2023) to 120,000 (2034) Internal Combustion Engine vehicles over their lifetime. The impact on wholesale price is between £0.70/MWh and £6.00/MWh, of which a material proportion could be used to reduce customer bills.
Detailed summary reports are produced for Stage 1 that outlines the methodology in detail, the sources of any data used, and presents key findings in a clear and understandable way. This should incorporate the effect additional network headroom has on other aspects of the customer bill, including balancing system costs, network costs, and carbon accounting costs.	✓	Details of the methodology, data sources, and findings can be found in the two Stage 1 projects available on the Headroom – Whole System Thinking project page.
Stage 2 Success Criteria		
A successful expert workshop is held, with attendance from National Grid DSO, NESO, and project partners. The outcomes of the workshop	✓	Engagement throughout the project was held at pivotal decision points. NGED DSO staff provided resource to complete curtailment analysis using NGED's Simple Curtailment Tool in Stage 2. Furthermore, outputs from Baringa's power market modelling analysis were verified by National Grid's Market Analytics team.

Success Criteria	Achieved	Performance
have successfully directed the project towards maximum value.		
Incorporate constraints based on individual voltage levels into PLEXOS to understand the proportion of available low carbon distribution connected generation that is curtailed, which otherwise supports the merit order effect.	✓	Curtailment profiles were established on a voltage level, technology type level, and half hourly basis, before being aggregated into an hourly model suitable for PLEXOS. Considering voltage levels in the 2034 study year: LV experienced 11% of DG curtailed in 2034, mostly solar assets HV experienced very little curtailment due to demand reinforcement assumptions, which increased capacity ahead of demand constraints as per the business plan. EHV experienced ~1.5% of available export curtailed, 132kV experienced 4% of available export curtailed.
Develop an understanding of how the proportion of renewable generation affects the wholesale price. During Stage 2, this will be at a national level with detailed consideration of whether demand and generation assets are connected to the distribution network or transmission network.	✓	**Merit-order price suppression** As you bring more zero-marginal-cost renewables into the dispatch stack, they displace gas-fired plant at the margin, shaving a few pounds per megawatt-hour off the average market price. In the Best-View case (with “released headroom” curtailment profiles), the modelling finds an average wholesale price saving of £1.9 bn over 2023–34, equivalent to roughly £2–3 /MWh of suppression at peak renewables penetration. Price-duration curves in the report show the biggest downward price shifts occurring in high-renewables hours (mid-day summers), but a persistent few-pound effect right through the year. **Grid carbon-intensity reductions** By running more low-carbon generation instead of fossil-fired units, the system avoids 1.95 $MtCO_2$ of emissions in the 2023–34 period under Best-View. Translating that into an average intensity, the report estimates a drop of ≈5–10 gCO_2/kWh across the decade when comparing the released-headroom case to a constrained-network baseline. This “dual benefit” of lower prices and lower intensity is presented as a strong no-regrets lever for DSO investment: every MWh of curtailed renewables you unlock not only earns back £2–3 but also cuts 0.2–0.3 kg CO_2.

Success Criteria	Achieved	Performance
Provide an understanding of the scale of benefit increased distribution headroom may have in terms of £/MWh, and CO2/MWh. At Stage 2, this will explore what times of the year the benefit is largest but also consider the relative split between GB wide free dispatch and the benefit gained from increased distribution network headroom.	✓	The scale of benefit increased headroom may have on the distribution network was assessed for 2023, 2028, and 2034. An hourly model was established, which determined the benefit throughout the year. Stage 2 forecast greatest benefit during the summer months, which coincides with the increased volume of Solar PV export as well as the outage window where our network has lowest capacity. Each study year featured sensitivity of the volume of curtailment experienced, and the scale of benefit per unit of curtailment was calculated as around £100/MWh for each study year. Carbon emissions fell over the study year, with a difference between curtailed and uncurtailed scenarios falling from 0.24 Mt to 0.08 Mt in 2034. The accumulated carbon cost was £213m, significantly less than wholesale market costs and ancillary market costs.
Detailed summary reports are produced for Stage 2 that outlines the methodology in detail, the sources of any data used, and presents key findings in a clear and understandable way. This should incorporate the effect additional network headroom has on other aspects of the customer bill, including balancing system costs, network costs, and carbon accounting costs.	✓	Two reports were authored in Stage 2, the first authored by EA Technology covers the curtailment analysis, the second authored by Baringa describes the market modelling and ancillary service modelling. Both are available on the National Grid webpage for the project.

7. Required Modifications to the Planned Approach during the Project

During the project, two change requests were issued and approved following National Grid's project management governance. Both were required to update the scope of the project towards outcomes deemed most valuable by the NGED DSO project sponsor while still meeting the objectives and success criteria set out for the project.

Change request 1: June 2024

Following the Stage Gate Review between Stages 1 and 2, the scope of Stage 2 and 3 was refined based on the feedback given in the End-of-Stage 1 workshop. This required the following modifications:

Additional Stage 2 Network Modelling:

- Refinement to EATL's Transform™ modelling to increase the number of representative days used in generating a forecasted annual curtailment profile driven by network constraints, inclusion of abnormal running arrangements within Transform™ development of more realistic BESS profiles, and benchmarking against historic and forecasted curtailment volumes. This was made to improve the accuracy of the annual profile, required to perform a full year's curtailment modelling, but not possible with the existing four representative days scoped at the beginning of the project.
- As Transform™ could not study 132kV networks or GSP constraints, NGED's Simple Curtailment Tool was used to forecast curtailment across 17 Grid Supply Points within NGED's licence areas.

Additional Stage 2 Power Market Modelling:

- In addition to the work agreed previously for Stage 2, Baringa would conduct more thorough PLEXOS analysis to create representative cost curves detailing the magnitude of system wide benefit when considering the spectrum of curtailment, which may be incurred.
- Provision for 22 additional PLEXOS runs to determine Headroom cost curves using multiple sensitivities.
- Increased Subject Matter Expert (SME) involvement within the Ancillary Services modelling team to establish cost curves.
- Provision for increased costs incurred in Stage 1 of the project.

National Grid Project & Programme Management:

- Due to the increased stage duration required to undertake the additional modelling (23 weeks compared to the original 10), additional project and programme management time was required.

De-scoping of Stage 3:

- Based on feedback from the NGED Project Sponsor, the overall objectives of the project were met within the revised Stage 2 plan.
- Stage 3 originally involved moving towards a Zonal Market model within PLEXOS, to understand the relative benefit of headroom on a geographic basis, along with an understanding of how the value Headroom can bring will be affected by a move to locational marginal pricing.
- Following feedback, and changes in National Policy regarding Locational Marginal Pricing (LMP) the priority of these features was reduced.

- Considering the increased workload of Stage 2, it was proposed to de-scope several aspects of Stage 3 and re-utilise the budget for the additional work proposed in Stage 2.

Change Request 2: April 2025

During Stage 2 of the project, an additional change request was issued to account for additional National Grid time spent on the project:

- This change was largely due to increased internal resource spent on the project during Stage 2 delivery, delivering aspects of the 132kV network curtailment modelling in conjunction with EA technology, and reviewing technical outputs. Whilst within scope of the previous change request, this activity took more time than forecast and utilised a larger proportion of the project budget than previously allocated. This change facilitated more detailed network analysis, stronger review of outputs, and further dissemination of the project's key findings to internal and external stakeholders.

8. Project Costs

Table 8-1: Overall Project Spend

Activity	Budget	Change Request	Actual	Variance compared to budgeted cost (%)	Variance compared to change request (%)
Baringa	£342,450.00	£319,680.00	£319,680.00	-7%	0%
EA Technology Ltd	£86,299.00	£193,406.00	£193,406.00	124%	0%
National Grid	£65,358.00	£109,651.19	£99,902.96	53%	-9%
Contingency	**£49,410.72**	**£0.00**	**£49,410.72***	0.0%	0%
Totals	**£543,517.87**	**£622,737.19**	**£612,988.96**	13%	-2%

* Use of contingency included in Project Partner Costs

Comments around variance

As outlined in Section 7, two change requests were issued during the project which de-scoped Stage 3's activities, and increased the analysis required for Stage 2.

- For **National Grid** this increased the total project spend as additional analysis was required to conduct SCT modelling, and to cover the Project Management time due to the extension of project duration.
- For **Baringa** the removal of Stage 3's funding was used partially to cover the scope increase of the revised Stage 2, resulting in an underspend compared to the initial budgeted cost.
- For **EA Technology Ltd** the additional scope of Stage 2's network analysis was not covered by the removal of Stage 3, therefore a change request (section 7) was raised to cover an increase in project cost.

9. Lessons Learnt for Future Projects and outcomes

Stage 1 Learnings

Curtailment modelling

- **Summer-only view hide's risk.** The Transform™ model used just four DFES representative days; only the "summer-peak-generation" profile contained export, so all forecast curtailment fell in June-Aug and around midday – essentially a PV-only problem. *Lesson:* other DNOs using similar snapshots will underestimate winter wind or shoulder-season constraints and may time-lag reinforcement.
- **Solar PV is the dominant LV–EHV driver.** Even within that limited window, PV curtailment set the pattern for all technologies, peaking at 12-15 h. *Lesson:* voltage-rise limits, not thermal headroom, are likely to bite first in high-PV regions.
- **Behavioural assumptions on BESS swing results.** Static "charge-at-night / discharge-at-midday" profiles overstated curtailment; the report recommended revisiting battery profiles and even regulatory reform to give operators confidence in BESS benefits. *Lesson:* network studies should iterate battery operating envelopes with developers to avoid pessimistic blocking of BESS connections.
- **Parametric averaging masks local hotspots.** The coarse archetype approach may under-report HV constraints where real feeders have far less voltage headroom. *Lesson:* supplement top-down tools with connectivity-based, feeder-level analysis before refusing or heavily constraining schemes.
- **No demand-driven reinforcement.** Stage 1 froze asset ratings, so curtailment simply grew with DG; this overstates risk where demand growth will trigger uprating anyway. *Lesson:* align curtailment forecasts with your investment planning rules for a fairer picture of "natural" headroom release.

Power-market modelling

- **Range-finding benefit test.** Two cases – *Network Curtailment* (low) vs *Maximum Constrained Generation* (high) – produced a 2023-34 wholesale system-cost saving between **£0.32 bn and £17 bn**. *Lesson:* even crude curtailment data showed headroom is potentially worth multiples of typical DNO reinforcement budgets.
- **Price and carbon impacts concentrate in tight margins.** Winter evenings saw the sharpest price uplift (up to £10/MWh) and carbon penalty when headroom was absent. *Lesson:* releasing distribution constraints is system-critical precisely when consumers and NESO need it most.
- **Uncertainty driven by network data.** Modellers flagged that summer-only LV/HV curtailment drove the enormous benefit range and ignored 132 kV entirely. *Lesson:* give market analysts year-round, voltage-segmented curtailment series or risk misleading planning decisions.
- **Early signal for DER services.** Value of lost Balancing-Mechanism and ancillary-service opportunities was highlighted but not quantified, hinting at extra upside as NESO widens <1 MW access.

Stage 2 Learnings

Curtailment modelling

- **Methodology upgrades deliver year-round realism.** Twelve seasonal representative days, demand-driven reinforcement, realistic grid-scale & domestic BESS cycling, V2G uptake, and planned-outage deratings replaced the Stage 1 simplifications.

Lesson: other DNOs can borrow this modular improvement list to tighten their own headroom studies.

- **Curtailment triples and migrates downstream.** Annual curtailed energy rises to **8.5 TWh by 2034**, enough to power 3.2 M homes; after 2030 the LV network overtakes 132 kV as the largest source, driven by domestic PV voltage rise.
  Lesson: investment priority shifts from early 132 kV bulk schemes to mass-LV voltage solutions later in the decade.
- **Solar dominates forecasted curtailment, but wind & BESS matter upstream.** Solar accounts for **4.8 TWh** curtailed in 2034, yet decision-tree analysis shows BESS exports are now the single biggest predictor of 132 kV curtailment.
  Lesson: operators must model BESS dispatch flexibly and examine whether ANM set-points are inadvertently blocking batteries.
- **Seasonal diversity emerges.** EHV/132 kV curtailment in winter and shoulder months grows because of wind and gas generation.
  Lesson: winter constraints are coming – don't rely solely on summertime voltage solutions.
- **Model limitations acknowledged.** EA Technology notes that parametric averaging still smooths out feeder extremes and advocates a follow-on connectivity-based tool.
  Lesson: granular digital-twin style tools are the next step to target reinforcement precisely.

Power-market modelling

- **Best-view whole-system benefit ~£2.5 bn (2023-34).** £1.93 bn wholesale, £0.21 bn carbon and £0.35 bn balancing-service savings when Stage 2 curtailment is removed. This equates to ~77% wholesale, ~14% balancing, ~9% carbon
  Lesson: that is equivalent to ~£200 m/yr – a material addition to business-case appraisals.

- **Voltage segmentation sharpens targeting.** LV delivers **37 %** of cumulative benefit by 2034 (£796 m) while 132 kV provides **53 %** early on but falls thereafter.
  Lesson: regulators and investors can tie funding to time-phased, voltage-specific benefit streams. Focus on 132kV capacity in the short term, with LV related interventions required during RIIO-ED3.
- **Benefit elasticity highlights policy risk.** Varying curtailment ±80 % swings benefit between **£0.49 bn and £3.9 bn**.
  Lesson: headroom value balloons if renewables race ahead faster than grid build – a realistic outcome under Clean-Power 2030 ambitions.
- **Data science confirms cascading effects.** Models show LV PV curtailment explains most HV/EHV constraints, and 132 kV is increasingly BESS-driven.
  Lesson: releasing LV headroom can relieve upstream networks, reinforcing the case for coordinated planning across voltages.
- **NESO-DSO coordination is non-negotiable.** Curtailment that blocks DER participation pushes up balancing costs; primacy rules, real-time data exchange and ANM upgrades are flagged as prerequisites.
  Lesson: treat curtailment as a priced action in both ANM and NESO markets to avoid counter-productive dispatch.
- Using **Balancing Services data alone under-scopes NESO costs**; a framework that includes **BM and bilateral actions** is required to capture true system impacts.
- *Lesson:* Prioritise better data sharing between DSO ANM and NESO, to avoid burdening the ancillary services market with unavailability of Distribution connected assets.

10. The Outcomes of the Project

How was the project used within National Grid?

The project was aimed to provide network operators such as National Grid an improved understanding of where additional network headroom can provide the greatest benefit to consumers, via a reduction in their energy bills. Whilst a direct saving did not occur during the project, the most significant outcome of the project is the ability for network operators to quantify the benefit of additional headroom as ~£100/MWh.

This is a figure quoted in National Grid's DSO benefit report, submitted to Ofgem. Looking forwards, further applications of this benefit will be explored, including ceiling prices for flexibility procurement.

The sensitivity study which suggested which voltage levels would have the greatest impact on wholesale markets has highlighted areas which NGED are looking to develop capabilities further. Greater voltage control on the LV networks is a key step to better allow more renewables such as Solar PV to export freely. These are capabilities being explored in projects such as LV ACT and Phase Switch System.

Dissemination

Throughout the project, learnings have been disseminated internally within the UK, as well as to an international audience. Several online webinars have occurred during the delivery of the project, as well as in-person presentations at industry events.

Table 14: Dissemination throughout the project

Event	Topics Discussed	Location
26toZero	Stage 1's learning and sensitivity studies	London, United Kingdom
CIRED 2024 workshop	Stage 1 Learnings from the project.	Vienna, Austria
Energy Innovation Summit 2024	Stage 2's network modelling updates, particularly focusing on the updated BESS profiles	Liverpool, United Kingdom
EATL hosted webinar	Online webinar presented to Asian, Australian, and New Zealand market, focussed on the key learnings from Stage 1 and updates made to network forecasting in Stage 2.	Online
CIRED 2025 conference	Overall project learnings, focussed on the voltage-based sensitivity analysis, and recommendations for future work.	Geneva, Switzerland

EATL hosted webinar	Overall project learnings, focussed on the voltage-based sensitivity analysis, and recommendations for future work.	Online

11. Data Access Details

All reports and supporting work are published on the ‘Headroom - Whole System Thinking’ project page accessible on the NGED website. Additional data can be requested by contacting NGED directly by emailing nged.innovation@nationalgrid.co.uk.

NGED data can be requested via the National Grid Connected Data Portal https://connecteddata.nationalgrid.co.uk

www.nationalgrid.co.uk/innovation/contact-us-and-more

12. Foreground IPR

The Relevant Foreground IPR is:

- All deliverable reports and documents produced during the project delivery.

The Relevant Background IPR required to produce this is:

- National Grid’s network modelling data including the Simple Curtailment Tool
- The PLEXOS model used by Baringa
- The Transform™ tool used by EA Technology Ltd.

13. Planned Implementation

The project's learnings have been and continue to be implemented into the business in two key areas.

Firstly, within the Future Capability team, insights on where network headroom provides greatest financial value to the energy system has directed our strategy and roadmaps towards projects that release capacity on the LV network, and 132kV network.

Secondly, the DSO team have adopted figures output by the project in their benefit reporting exercise. Details of this is expanded in Section 10: Outcomes of the Project.

14. Contact

Further details on this project can be made available from the following points of contact:

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15. Glossary

Term	Explanation
0.4 kV / 11 kV / 33 kV / 132 kV / 400 kV	Common UK electricity distribution and transmission voltage levels (kilovolts).
Abnormal running	Temporary network configurations during planned maintenance or faults, where circuits operate outside usual topology, often reducing capacity.
ANM	Active Network Management – control systems that curtail or manage distributed generation in real time to maintain safe operation of the network.
Archetypes	Representative network models (urban, suburban, rural) used in modelling to generalise behaviour across the system.
BESS	Battery Energy Storage System – large-scale batteries connected to the grid for balancing, storage, and flexibility.
BM	Balancing Mechanism – the real-time market operated by NESO to balance supply and demand.
BS	Balancing Services – markets procured by NESO for ancillary services such as frequency response, reserve, etc.
CPS	Carbon Price Support – a UK tax on fossil fuel generation, set in £/tonne of CO_2.
Curtailment	Reduction in output of generators (e.g. wind, solar) due to network or market constraints.
DNO	Distribution Network Operator – companies licensed to operate regional electricity distribution networks.
DSR	Demand Side Response – flexibility provided by customers adjusting consumption in response to system needs.
DSO	Distribution System Operator – the evolving role of DNOs in actively managing distributed generation, demand, and flexibility.
EA Technology, EATL	Consultancy providing the “Transform™” model used for distribution network modelling.
ECR	Embedded Capacity Register – dataset of distributed generation and BESS connected to the distribution networks.
EHV	Extra High Voltage – typically 33–132 kV parts of the distribution network.
Embedded generation	Generation connected to the distribution network rather than transmission.
ESO / NESO	National Electricity System Operator – formerly known as NESO.
EVCP	Electric Vehicle Charging Point.
FES	Future Energy Scenarios – annual National Grid NESO scenarios exploring possible energy futures.
GB	Great Britain – geographic scope of the project.
GSP	Grid Supply Point – the interface between the transmission network and the distribution network.
Headroom	Spare capacity in the network before reaching thermal, voltage, or stability limits.
HV	High Voltage – typically 6.6–33 kV distribution networks.
IPR	Intellectual Property Rights.
LCT	Low Carbon Technology – includes EVs, heat pumps, PV, and BESS.

LV	Low Voltage – typically 230/400 V distribution networks.
Mt	Million tonnes – used for carbon emissions measurement.
N-1 / N-1-1	Security standard where the system must withstand one (N-1) or sequential (N-1-1) component outages without widespread failure.
NGED	National Grid Electricity Distribution – the DNO covering the Midlands, South West, and South Wales.
Ofgem	UK energy regulator (Office of Gas and Electricity Markets).
Peak Generation Day	A representative day with high renewable generation and low demand.
Peak Demand Day	A representative day with high demand and low generation.
PLEXOS	Commercial software used for power market modelling and dispatch simulation.
PV	Photovoltaics – solar generation technology.
SGT	Super Grid Transformer – large transformers connecting transmission and distribution.
SCT	Simple Curtailment Tool – NGED's tool for estimating generator curtailment on networks.
SME	Subject Matter Expert.
V2G	Vehicle-to-Grid – technology enabling EVs to discharge electricity back to the grid.
UKA	UK Allowance – tradable carbon credit in the UK Emissions Trading Scheme.

Appendix 1: Transform™ Archetypes

Overview of the feeder thermal and voltage parameters in the Transform™ model. The two columns to the right of the table show the maximum load or generation that can be connected before legroom or headroom is breached respectively.

EHV Networks

Archetypes	Substation Capacity (kW)	Thermal Conductors Capacity (kW)	Planning Voltage Upper Headroom Limit (%)	Planning Voltage Lower Limit (%)	kW/%	Permitted kW prior to voltage headroom breach	Permitted kW to voltage legroom breach
EHV1 Urban Underground Radial	90000	25020	6%	6%	19300	115800	115800
EHV2 Urban Underground Meshed	45000	18000	6%	6%	18000	108000	108000
EHV3 Suburban Mixed Radial	60000	22260	6%	6%	7700	46200	46200
EHV4 Suburban Mixed Meshed	45000	18000	6%	6%	8600	51600	51600
EHV5 Rural Overhead Radial	48000	15240	6%	6%	18000	108000	108000
EHV6 Rural Mixed Radial	48000	16140	6%	6%	12500	75000	75000

HV Networks

Archetypes	Substation Capacity (kW)	Thermal Conductors Capacity (kW)	Planning Voltage Upper Headroom Limit (%)	Planning Voltage Lower Limit (%)	kW/%	Permitted kW prior to voltage headroom breach	Permitted kW to voltage legroom breach
HV1 Urban Underground Radial	4000	4504	6%	6%	6100	36600	36600
HV2 Urban Underground Meshed	2500	4567	6%	6%	5200	31200	31200
HV3 Suburban Underground Radial	3429	3552	6%	6%	3900	23400	23400
HV4 Suburban Underground Meshed	1875	3121	6%	6%	3300	19800	19800
HV5 Suburban Mixed Radial	6000	3400	6%	6%	440	2640	2640
HV6 Rural Overhead Radial	2400	2474	6%	6%	280	1680	1680
HV7 Rural Mixed Radial	2400	3045	6%	6%	800	4800	4800

LV Network

Archetypes	Substation Capacity (kW)	Thermal Conductors Capacity (kW)	Planning Voltage Upper Headroom Limit (%)	Planning Voltage Lower Limit (%)	kW/%	Permitted kW prior to voltage headroom breach (kW)	Permitted kW to voltage legroom breach (kW)
LV1 Central Business District	238	231	1%	15%	40	40	600
LV2 Dense urban (apartments etc)	190	164	1%	15%	40	40	600
LV3 Town centre	190	179	1%	15%	40	40	600
LV4 Business Park	238	184	1%	15%	40	40	600
LV5 Retail Park	238	184	1%	15%	40	40	600
LV6 Suburban Street (3-4 bed semi-detached or detached houses)	119	111	1%	15%	40	40	600
LV7 New build housing estate	119	164	1%	15%	40	40	600
LV8 Terraced Street	119	111	1%	15%	40	40	600
LV9 Rural village (overhead construction)	48	131	1%	15%	40	40	600
LV10 Rural village (underground construction)	100	113	1%	15%	40	40	600
LV11 Rural farmsteads small holdings	48	56	1%	15%	40	40	600
LV12 Meshed Central Business District	380	359	1%	15%	40	40	600
LV13 Meshed Dense urban (apartments etc)	190	328	1%	15%	40	40	600
LV14 Meshed Town centre	190	359	1%	15%	40	40	600
LV15 Meshed Business Park	190	369	1%	15%	40	40	600
LV16 Meshed Retail Park	190	369	1%	15%	40	40	600
LV17 Meshed Suburban Street (3-4 bed semi-detached or detached houses)	190	226	1%	15%	40	40	600
LV18 Meshed New build housing estate	190	226	1%	15%	40	40	600
LV19 Meshed Terraced Street	190	384	1%	15%	40	40	600

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