Whole of System Value of Distribution Headroom

End of Stage 1 Report v2.0

CLIENT: National Grid Electricity Distribution

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baringa.com

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Version history

Version	Date	Description	Prepared by	Approved by
1.0 to 1.4	22-Jan-24 to 22-Mar-24	Drafts with revisions to reflect client comments.	Abbas Husain, Chris Collins, David Middleton, Sanjay Rathod, Yingjian Guo with input and comment from EATL and NGED.	Mike Wilks, Baringa
2.0	25-Mar-24	Approved by client.	David Middleton.	Laurence Hunter, NGED

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1 Executive Summary

The distribution networks need to adapt to accommodate significant load growth associated with the decarbonisation and electrification requirements to meet the 2050 Net Zero targets. Crucial to this will be the difference between network load and network capacity (Headroom). A lack of Headroom at different voltage levels could limit this growth and the ability of connected parties to access and participate freely in wholesale and / or flexibility markets and affect the optimisation of the costs and carbon intensity of the whole electricity system.

This report quantifies the whole system value associated with releasing Headroom across all GB electricity distribution networks across three years (2023, 2028 and 2034) to determine the total value of Distribution Network Headroom in the energy market and potential carbon cost savings.

This was undertaken using a low Headroom impact scenario and a high Headroom impact scenario to estimate the level of curtailment on different generation and storage technologies. The market model used the Baringa Net Zero High scenario which assumes ambitious decarbonisation targets, high penetration of renewable generation to determine the benefits of releasing Headroom (consistent with FES ST). The analysis during this Stage 1 provides a high-level estimate of the potential impact of releasing distribution network headroom on wholesale prices, Balancing Mechanism, and carbon emissions. The system and carbon benefit outcomes reported here rely on the network curtailment simulation data and the market model network representation. The Stage 1 result is used to inform a more detailed network curtailment simulation or Stage 2.

The output of the market model together with an evaluation of Balancing Mechanism effects show that releasing Headroom could bring significant benefits for the GB system:

- 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.

Recommendations are made for work to be conducted during Stage 2 of the project.

There is a wide range of annual benefit from releasing Headroom that varies from material (£27.5m) to significant (£1.4bn). It is proposed this project continues with Stage 2 to confirm the materiality of the benefits and to narrow the range from releasing Headroom through more detailed constraint modelling and the production of high-level price curves to represent the range of benefits.

2 Introduction

The delivery of GB Net Zero targets for 2050 will involve a significant increase in the electrification of transport and heat. National Grid Electricity System Operator (ESO) publishes Future Energy Scenarios (FES)[1] annually that outlines four credible ways to achieve net zero by 2050 and operate a decarbonised electricity system by 2035. These are used by Distribution Network Operators (DNOs) to understand how customers will use electricity distribution networks and how to accommodate these needs[2]. The growth of renewable generation (particularly solar PV and wind) and batteries are already causing constraints on the electricity distribution networks and in the wider electricity system.

Sufficient capacity is required to enable this increased use of the electricity distribution network. A lack of available capacity on the distribution network, calculated as the difference between load and network limits (Headroom) at different voltage levels could limit the extent to which Distributed Energy Resources (DERs which in this report means distribution connected generation and storage) can access and participate freely in wholesale and / or flexibility markets and affect the optimisation of the costs and carbon intensity of the whole electricity system[3]. Understanding the value to the whole system of Headroom on the electricity distribution network will benefit the targeting of innovation resources and support investment decisions in Business as Usual. The process to determine the whole system value of Headroom is summarised in Figure 1.

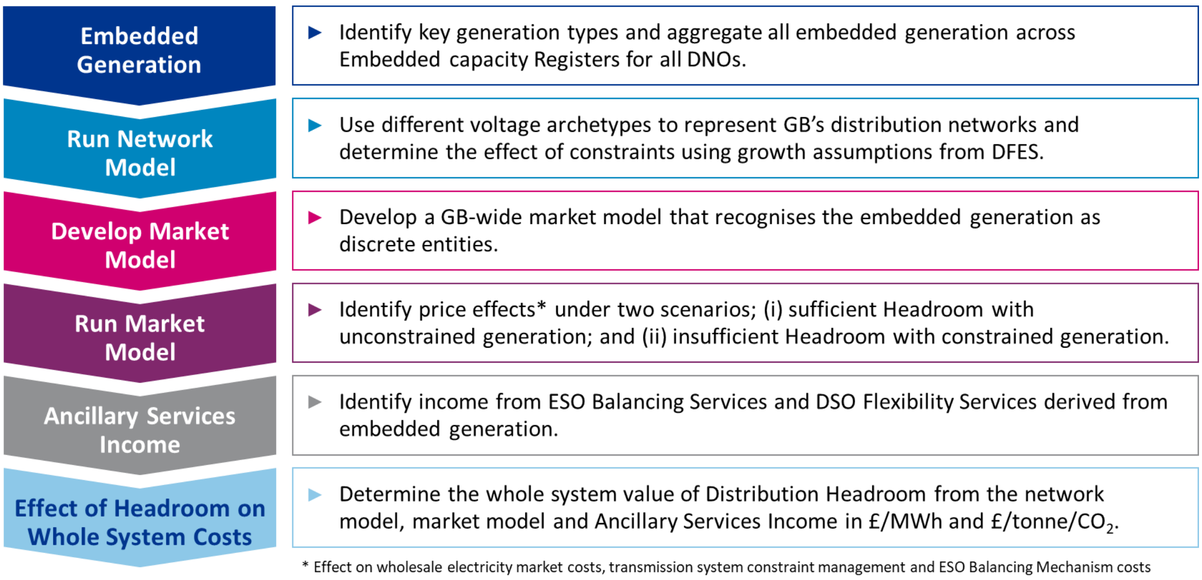

Figure 1: High Level Process to Determine Whole System Value of Distribution Headroom

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[1] National Grid ESO Future Energy Scenarios

[2] The FES provides the basis for Distribution Future Energy Scenarios (DFES).

[3] In this context, the whole electricity system comprises; wholesale electricity markets, transmission system constraint management, distribution network constraint management, and system balancing activities; discussed further in section 3.

3 Scope of this Report

This report quantifies the whole system value associated with releasing Headroom across all GB electricity distribution networks across three years (2023, 2028 and 2034) to determine the total value of Distribution Network Headroom in the energy market and potential carbon cost savings.

The scope of this report is to conduct a sensitivity analysis into the incremental value of Headroom to DERs aggregated across three years (2023, 2028 and 2034) under two scenarios and represented as a range of values for Headroom in energy (£/MWh) and carbon (£/tonne CO_2) terms.

The overall project comprises three stages with the level of analysis increasing in detail and granularity:

- Stage 1 – determine the range of potential benefits of releasing distribution Headroom on wholesale prices, Balancing Mechanism, and carbon emissions using a high and a low Headroom impact scenario. This is discussed further below.
- Stage 2 – refine the potential benefits of distribution Headroom at different voltage levels[4] to produce a variety of high-level cost curves.
- Stage 3 – determine detailed cost curves for the potential benefits of distribution Headroom and how this varies with nodal energy markets.

This report focuses on Stage 1 which was delivered across three Phases:

- Phase 1: Define conceptual Headroom-value relationship (addressed in section 4):
  - Define qualitatively how Headroom creates value for the electricity system.
  - Agree the logic for translating a Headroom shortfall into an impact on generation, storage, and demand.
- Phase 2: Define representative Headroom[5] (addressed in section 5.1):
  - Agree network archetypes for each voltage level and the associated DERs.
  - Determine the aggregate level of DERs across all DNOs.
  - Conduct network modelling to determine level of constrained DERs.
- Phase 3: Determine the benefits of incremental Headroom (addressed in sections 5 and 6):
  - Establish market model that recognises DERs connected to the distribution networks.
  - Run market model for an unconstrained and constrained network to determine the difference in energy and carbon price attributable there was sufficient Headroom.
  - Determine the Balancing Services benefit from Headroom in energy and carbon price.

[4] The voltage bands are LV (up to and including 1kV), HV (1.1kV to 11kV), EHV (11.1kV to 66kV) and 132kV.

[5] For the purposes of this report, it was agreed that Fault Level Headroom of existing switchgear was out of scope and has been excluded from this report.

4 Distribution Network Headroom

Headroom is the available capacity on a DNO asset and is the difference between load and network limits. Headroom indicates capacity available to accommodate an increase in generation (at minimum demand, peak generation times) or an increase in demand (at minimum generation, peak demand times) from the existing level. It enables the connection of new or additional loads without overloading the network or degrading its performance and affects many areas of network operation, including capacity planning, level of flexibility to respond to changes in loading due to planned or unplanned events, informs investment in new capacity, and affects the reliability and availability of the network.

There are occasions when there is insufficient Headroom:

- In summer for Generation Headroom due to a high level of connected solar PV generation (the major embedded generation type during summer months) and reduced available capacity on the network in summer due to ambient temperatures.
- In winter for Demand Headroom due to a high level of connected demand (particularly large commercial loads such as data centres, restricted available capacity on the network until planned infrastructure at distribution or transmission level is commissioned, and high demand due to low ambient temperatures.

There are benefits in increasing Headroom in these situations to avoid generation curtailment and enable demand growth, but it may not be economically advantageous to increase Headroom for what could be a limited duration where other solutions exist, e.g. flexibility services. This study has focussed on the value of increasing distribution Headroom to avoid constraints on the whole electricity system.

For reporting purposes, a single maximum value of Headroom for generation and demand is used. However, Headroom varies dynamically during the year (primarily due to network loading, weather and network configuration) and this may enable more generation and / or demand to be accommodated outside of the maximum periods.

The process for determining the effect of Headroom in this project is outlined in Figure 2.

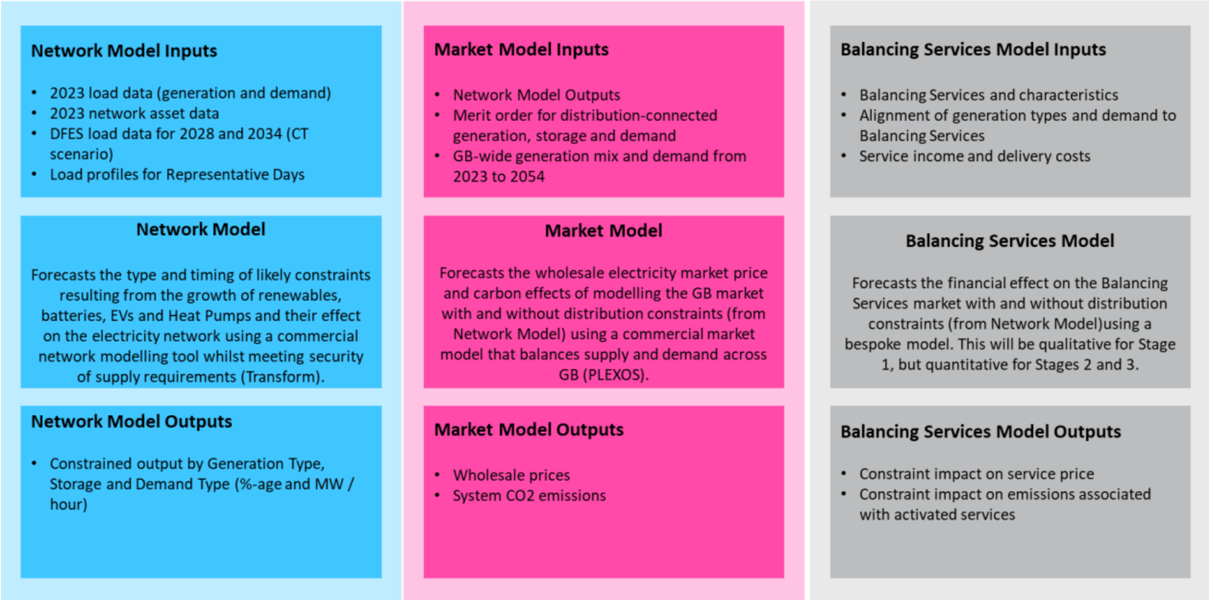

Figure 2: Process for Determining the Whole System Value of Distribution Headroom

5 Market Modelling

5.1 Approach and Methodology

5.1.1 Overview of Baringa market model

Baringa maintains a set of regularly updated wholesale power scenarios (Reference Case, Net-Zero, Net-Zero High, Low Commodities) for 30 markets including the GB, Ireland, and continental European markets. These 'Reference Case' scenarios are provided to a wide range of client subscribers across the industry, including utilities, developers, investors, and lenders.

The scenarios are developed with full consideration of wholesale market drivers including:

- Commodity prices, carbon prices and exchange rates.
- Demand trends (including electrification of heat and transport).
- Generation capacity build and retirement.
- Renewable energy deployment.
- Interconnector developments.
- Political and regulatory developments (e.g. Brexit, ECJ GB capacity market ruling).

The Baringa power market model[6] is used to simulate the power market investment and dispatch behaviour. Market intelligence around individual market regulation and capacity condition, technology cost and operational constraints are also input into the model to ensure the modelled condition best represent future deployment trajectory. The Baringa modelling framework with detailed inputs and outputs is summarised in

For this study, the day-ahead market model is the main model used to simulate the hourly power dispatch of more than 2,000 generators in GB and Europe over the period 2023 to 2060 to ensure the effects of new generation and retirements are correctly modelled. The result is determined on a least-cost basis, i.e. to minimise the costs of generation in any market. At its heart lies a dispatch 'engine' based on a detailed representation of market supply and demand fundamentals at an hourly granularity. The supply mix is represented with the operating parameters of generating plant including costs and operational constraints. The model determines economically rational market dispatch accounting for interconnection limitations on power transfer capacity between countries. This is summarised in Figure 3.

[6] Baringa uses PLEXOS, a highly regarded power market simulation software used globally by system operators, utilities, and commodity traders. It has been used extensively over the last ten years as a commercial tool to model power markets in detail.

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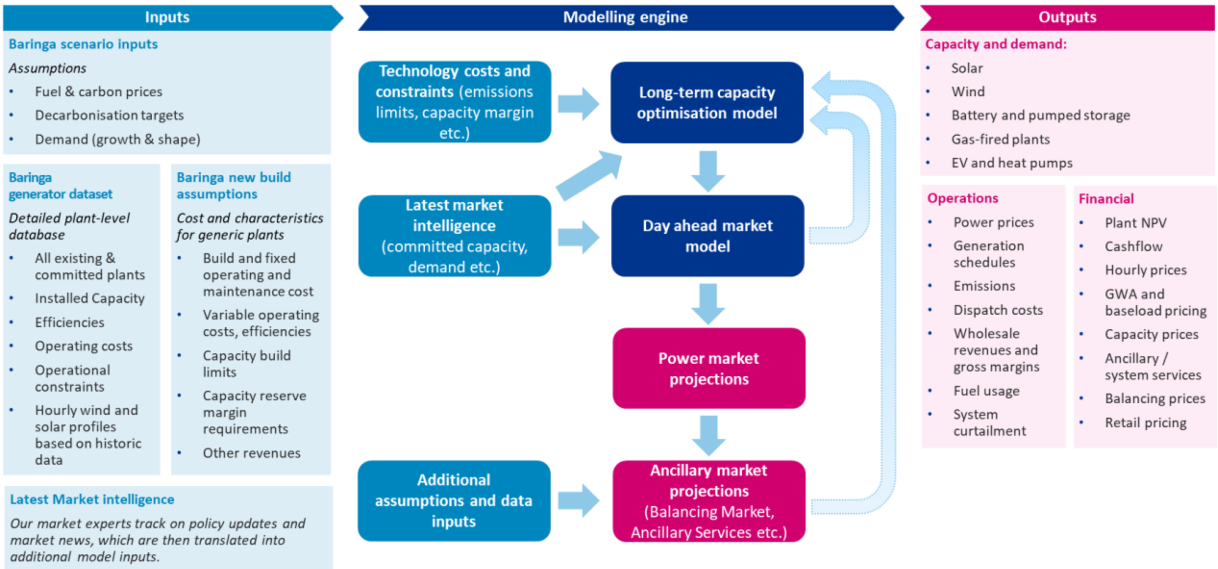

Figure 3: An overview of inputs, modelling mechanisms and outputs of market model.

Power demand in each hour is represented across five categories and is summarised in Figure 4. This comprises fixed demand (satisfied in full) and flexible demand (consumed in an optimal manner within specific constraints). The hourly load is determined by both historical demand profiles, new demand sources, and demand side flexibility. The level depends on the annual demand in a country, demand distribution within the year, and daily consumption pattern. Peak demand is one key metric used to assess the capacity adequacy (sufficient generation to meet demand) and drives new build capacities.

Demand segment	Description	Source
Conventional demand	Conventional demand covers all uses for electricity not covered by the segments below. Broadly, this covers demand as observed today (lighting, appliances, electric resistive heating). Projections account for GDP growth, offset by efficiency savings.	TSO and central government projections
Electric Vehicles	Road based EVs are projected to be a large source of demand growth, with EU and national governments committing to banning sales of new internal combustion engine (ICE) cars and other road transport. We use a detailed transport uptake model, using publicly available data for each country on current sales, typical driving distances, and dates of ICE bans.	Baringa transport uptake model
Heat Pumps	Heat pump projections use ENTSO-E TYNDP 2022 assumptions, together with EU and country ambitions in achieving Net Zero goals through electrified heating. EU proposals to reduce reliance on gas through the 2020s (following events in Ukraine) are represented in our projections. Electric resistive heating is classified as conventional demand and included in that demand segment.	Baringa analysis
Storage load	Storage load corresponds to the total annual demand from energy storage plants when charging, such as pump storage and batteries. We model supply and demand from energy storage separately, with demand being larger than supply due to losses. The operation (and therefore "demand") from storage technologies is modelled as part of our power market dispatch modelling.	Modelled result as part of Baringa power market projections
Hydrogen electrolysis	Demand for hydrogen in Europe uses the Baringa hydrogen demand model, which takes a bottom up approach to estimate demand requirements from all sectors of the economy. Baringa analysis is used to assess how much of this Hydrogen requirement should be "Green Hydrogen" (i.e. produced using electrolysis), based on economics, policy, and constraints around production technologies and global trade.	Baringa hydrogen demand model

Figure 4: Baringa Demand Segmentation

Long-term capacity investment and retirement decisions are based on projected profitability, assumed levels of decarbonisation and capacity margin targets. The capacity assumptions in Figure 5 show a steady increase in capacity over the period with an aggressive reduction in gas capacity at the front end and ambitious renewable energy sources (RES) assumptions driving the decarbonisation of the GB power market.

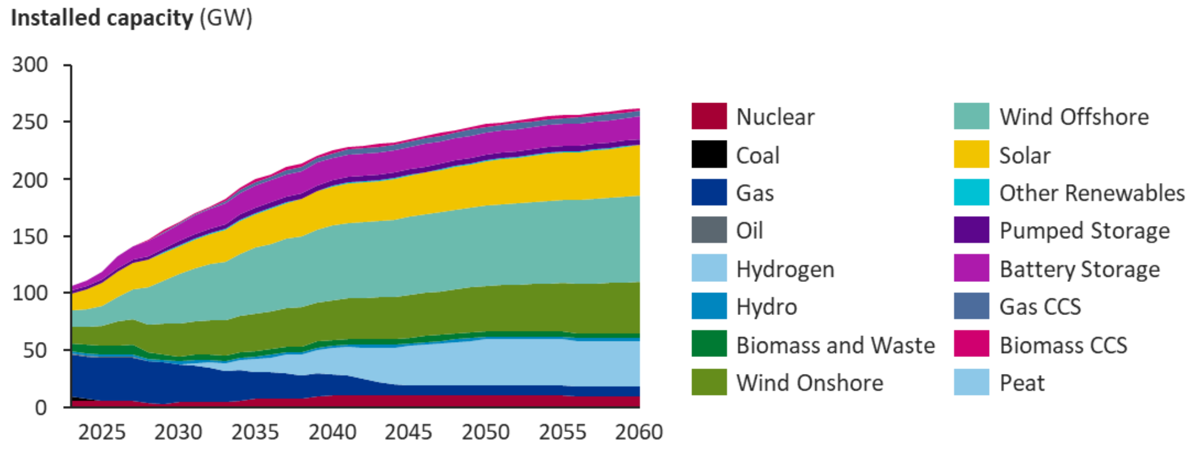

Figure 5: Capacity assumptions, Baringa Net Zero High

The model simulates over 30 markets including the GB, Ireland, Central Western Europe, Iberia, Nord pool, South and Eastern Europe (e.g. Italy, Czech Republic, Poland, Serbia) with underlying assumptions of the interconnected capacities. The cross-border flows between are determined by the relative cost and economy of generation in different markets. This is necessary to ensure the GB market is modelled correctly over the period 2023-2060.

Standard outputs from this modelling include hourly granularity for: system short run marginal cost, generation levels, emissions levels, fuel use, and interconnector flows.

5.1.2 Description of Baringa Net Zero High Scenario

Baringa's Net Zero High (NZH) case was selected as a basis for this study as it aligns closely with FES scenario System Transform (ST) which is used in the network modelling of curtailment.

In Baringa's NZH, most European countries achieve their net zero targets for the wider economy. High carbon pricing, as shown in Figure 6, is a key feature in this scenario, which provides signals for investment. Carbon price reaches £160/tonne by 2034 and plateaus at £260/tonne by 2050. In addition, there is significant growth in power demand due to accelerated and deeper electrification of transport and heat. In the projections, a Net Zero GB power market is achieved by 2035, meeting the Government's ambition for a decarbonised power sector. The overall UK economy reaches net-zero by 2050. A summary of scenario context is provided in Figure 7.

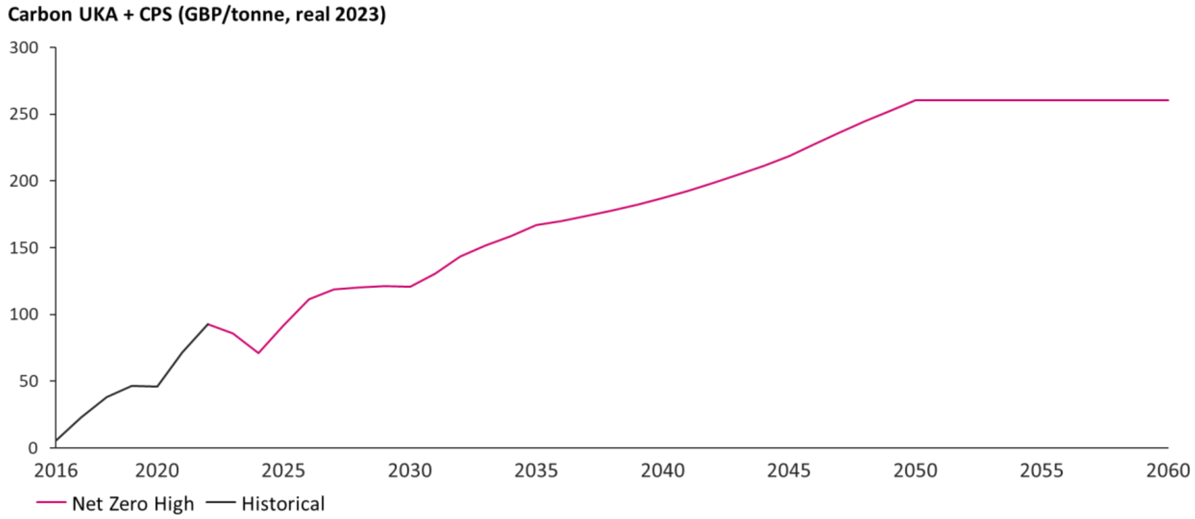

Figure 6: Carbon prices, Baringa NZH

	Net Zero High (NZH)
Net zero trajectory	Most European countries achieve their net zero targets for the wider economy. Public and government interest in achieving those targets is very strong. There is significant investment in low-carbon power technologies.
Demand	High level of electrification of transport, heating and industrial sectors. The drivers behind electrification are largely commercial, rather than policy driven.
Commodity and carbon prices	An initial increase in fossil fuel investment and exploration is dissuaded due to risk of price collapse. In the mid-term, governments restrict further investments in fossil fuels. Fuel prices remain higher for longer. Carbon pricing provides the key signal for investment in low-carbon technologies.
Technology costs	Overall, technology costs decrease over time due to learning rates and economies of scale achieved. Power prices are very volatile and dependent on intermittent renewable generation, increasing revenue risk and therefore WACC for low-carbon technologies.
Government support and intervention	Policy is focused on network and permitting bottlenecks for renewables. High carbon and power prices support merchant renewables. This enables merchant operation to be the main route to market for renewables.
Security of supply	Security of supply is partially ensured via capacity payment mechanisms and strategic reserve and partially by high energy market revenues

Figure 7: A summary of Baringa NZH

5.1.2.1 Description of Baringa scenario alignment with FES ST

DNOs have developed a "Best View Scenario" from their DFES that focuses on high certainty activities in the first 10 years to provide clarity and support optimal network planning that would not be available from a range of scenarios. It is intended to use the Best Fit Scenario during Stages 2 and 3.

Stage 1 will use the FES System Transformation scenario (FES ST) as there is a high correlation with the Best Fit Scenario and with the Baring NZH scenario and this is illustrated in Figure 8 . There are three Baringa scenarios (Reference Case, Net Zero and Net Zero High) and for each year in Figure 8 they are compared to FES ST. The percentages highlighted refer to the absolute difference in total peak capacity between each of the Baringa scenarios and the FES ST.

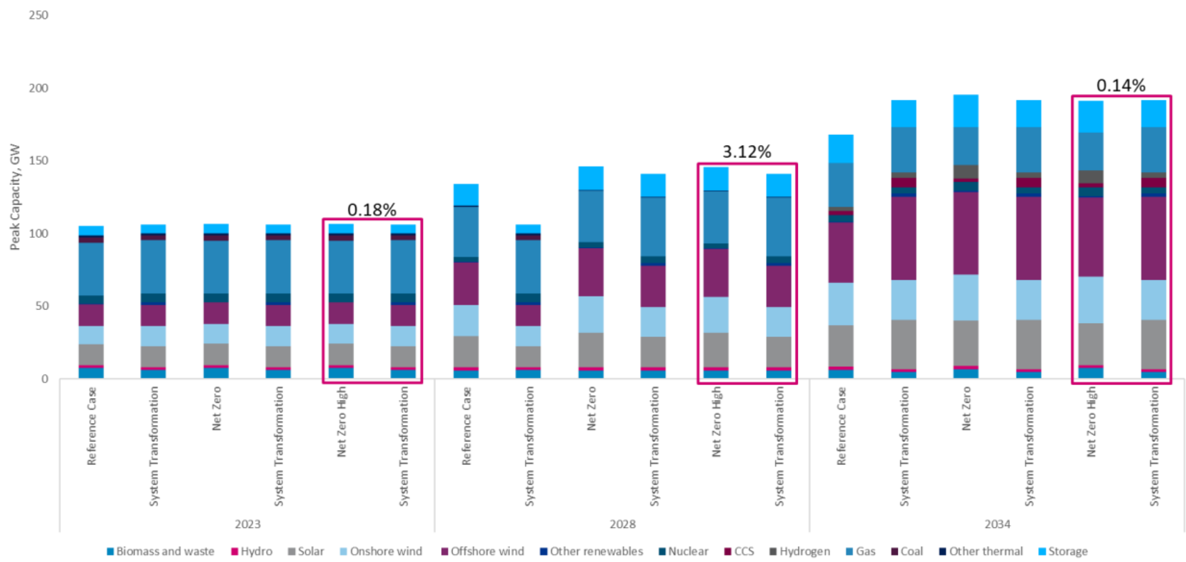

Figure 8: Comparison between FES System Transformation and Baringa Scenarios

Further analysis of the peak capacity for technology groups is provided in Figure 8. For each scenario, the bars represent the difference in peak capacity for a particular technology type between each Baringa scenario and the FES ST for that year. The height of the bar reflects the absolute difference in peak capacity between each Baringa scenario and the FES ST. Individual technologies are colour-coded and a positive value on a given bar refers to the fact that the Baringa scenario provides a higher estimate of peak capacity for that technology in that year than the FES ST. Conversely, a negative value implies that the Baringa scenario provides a lower estimate of peak capacity for that technology in that year compared to the FES ST.

The pair of FES ST – Baringa scenarios with the highest correlation is reflected in the bars with the lowest height. The percentage values provided below each bar provides the absolute difference between the aggregate peak capacity in each scenario pair. As shown in Figure 9, the Baringa Net Zero High provides the closest estimates to the FES ST across each of the study years.

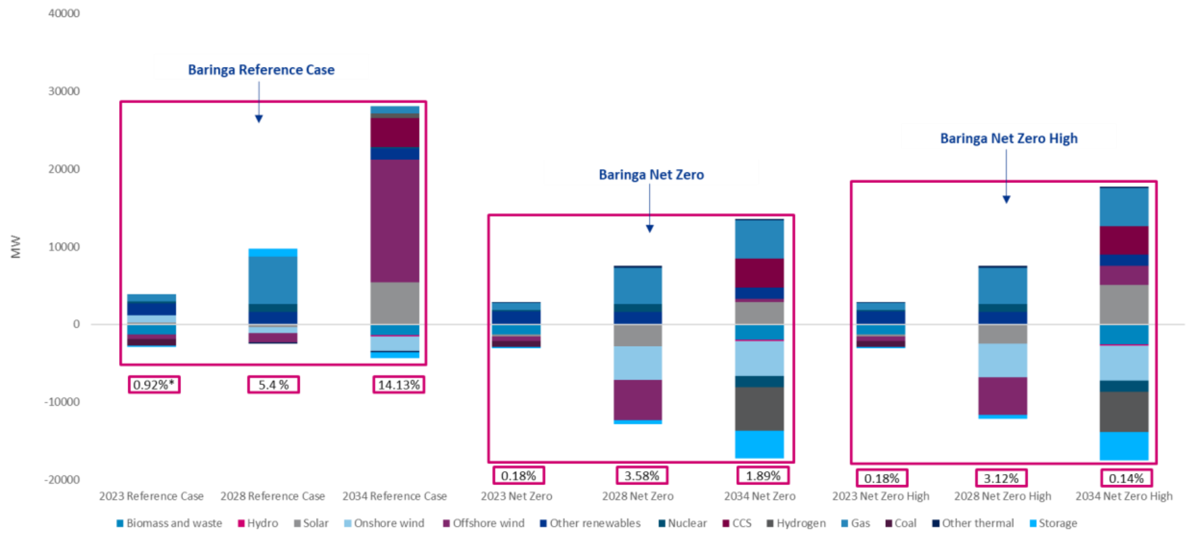

Figure 9: Comparison of Peak Capacity between FES System Transformation and Baringa Scenarios

On the basis of the analysis summarised in Figure 8 and Figure 9, it was agreed to use the Baringa NZH scenario for Stage 1 analysis as it best matches the peak capacity for technology groups of FES ST.

5.1.2.2 Embedded Capacity

The Embedded Capacity Register (ECR) is published by each DNO on their website and provides information on DERs that are connected, or accepted to connect, to the distribution network and is updated monthly. The register also includes information about Flexibility Services that are being provided by connected resources, including flexible demand. The analysis includes information on DERs with a capacity of up to and including 1MW and over 1MW.

Analysis of the ECRs for all DNOs was conducted in October 2023 and provides a single view of all DER technology types connected to distribution networks at different voltage levels. A summary of the aggregate peak capacity of all technology types across all voltage levels is summarised in Figure 10; **Figure 11** provides a summary of the aggregate peak capacity for each technology type for each voltage band.

The analysis of the ECRs provided input data for the network modelling conducted by EA Technology[7]. The data informed the proportion of each technology type installed on different network archetypes (rural, sub-urban and urban). The modelling also considered the effect of the time of year on the network model across four representative days used in network planning (Peak Winter Demand, Peak Summer Generation, Peak Intermediate Cool Demand, Peak Intermediate Warm Demand).

[7] "Headroom – Whole System Thinking: Stage 1 Report", EA Technology..

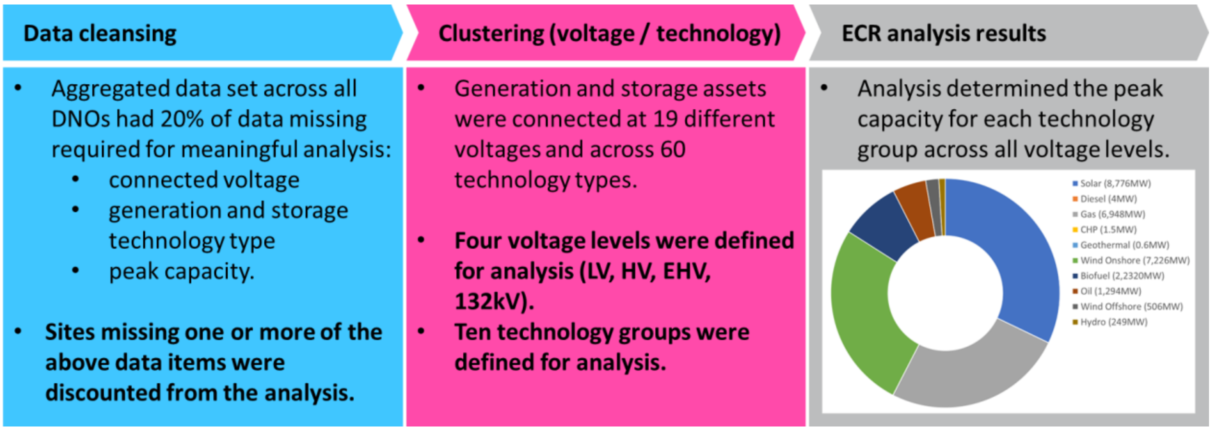

Figure 10: Process for analysis of ECRs

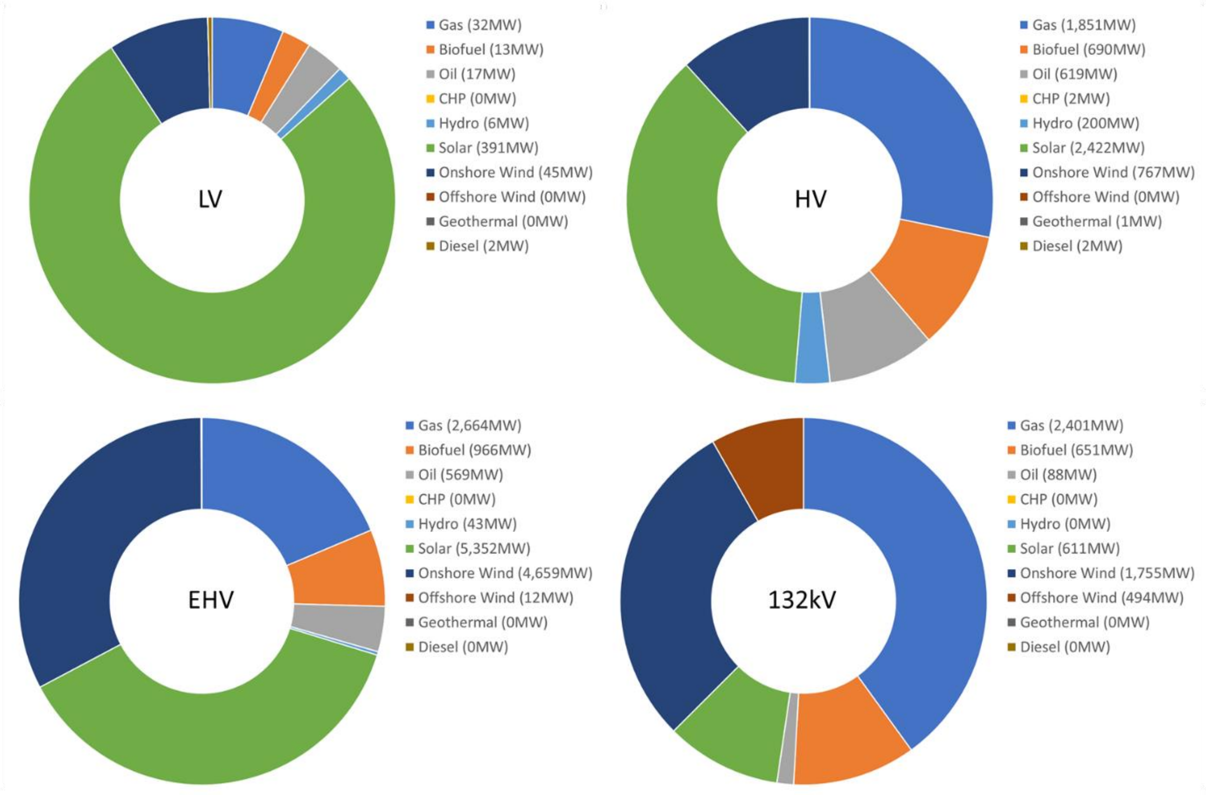

Figure 11: ECR Analysis Process (by voltage)

5.2 Market participation by distribution-level generators

Distributed Energy Resources (DERs) connected directly to the electricity distribution networks accounts for 30%[8] of all export capacity in GB. The ability of DERs to vary their output can be used to provide flexibility helps balance the system and manage network constraints. The ESO and DNOs procure these services either directly (subject to minimum capacity requirements) or through a third party, typically via suppliers or aggregators. Some of these services require exclusivity which may limit the ability to participate in other services. Additionally, flexibility may be used for trading energy in the wholesale market, typically via suppliers or traders.

In the 12 months to August 2023, DNOs had collectively contracted for 2,400MW of DERs or demand side flexibility across five services[9]. Although there is no comparable figure for ESO, conservative analysis of although a conservative estimate of Balancing Services revenue for decentralised generation could be ~£370m[10].

The range of services that could be provided from DERs is summarised in Table 1. Those labelled as 'Possible' may require specialist technical capabilities.

Table 1: Mapping of ESO Services to Technologies

Services[11]	Market	Battery	DSR	EVCP[12]	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

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[8] Definition of embedded generation, 05 February 2024.

[9] ENA ON GB Flexibility Figures 2023/2024, 05 February 2024.

[10] Analysis of the latest Monthly Balancing Services Summary reports indicates ancillary services represented an annual cost which exceeded £4.1bn (see section 6.3). FES 2023 Data Workbook V003, Tab ES.10 indicates 30% of generation was decentralised in 2022, rising to 27% by 2050 for the FES ST scenario. If 30% of this market is theoretically addressable by DER today, then Balancing Services revenue for decentralised generation could be ~£370mn.

[11] ESO Balancing Services; DNO services are excluded as they are unlikely to provide wider system benefits.

[12] Electric Vehicle Charging Point

Services[11]	Market	Battery	DSR	EVCP[12]	Gas Engine	Hydro run- of-river	Solar PV	Wind onshore
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

Under FES ST scenario, decentralised generation is expected to increase from 33.8GW in 2022 to 86.8GW in 2050 and should be providing a significantly higher proportion of Balancing Services, particularly given that the ESO has stated its intention to widen access to its balancing services[13].

5.3 Limitations of the Stage 1 analysis

There are several limitations of the Stage 1 analysis, including:

- Market model simulation is highly dependent on the curtailment input data[14]. Current network modelling takes different approaches to include 132kV (only represented in the Simple Curtailment Tool data set – see section 5.4.1) and other voltage levels (Transform modelling). The transform network modelling data only identified curtailment during summer months as the profiles within DFES only consider peak generation for summer, and peak demand for the other seasons. Solar PV was primarily affected, and other generators' pattern aligned with the times of solar PV curtailment.
- Market model simulates GB on a national level without considering detailed constraints on each transmission and distribution network
- The definition of volume of Headroom and the linkage between system benefits with releasing Headroom at a specific level could be further researched. Due to the complexity in distribution network system at different voltage level, benefit is not equally proportional to each "MW of headroom reduction".
- There can be expansion of represented years from Market Model to better understand the transition condition, especially for carbon impact.
- There is not a strong link between the day-ahead Market Modelling and the value for ESO services and it is uncertain if the lost value at day ahead and the missed value from ESO services resulting from constraints are additive or there is an element of double counting that should be recognised.

[13] ESO to make change allowing up to 300MW of flexible assets into the Balancing Mechanism

[14] The Transform simulation only considers the network constraints related to thermal and voltage limits. Curtailment is driven by when net export on the feeders / transformers are constrained by these asset limits.

5.4 Analysis framework

5.4.1 Network curtailment analysis

Network curtailment analysis was conducted using data from ECRs (as discussed in section 5.1.2.2) at two levels:

- **Network Model** – this has modelled the effects of restrictions of Headroom at voltages up to 66kV on the level of export from generation and storage. The model considers abnormal running arrangements by using reduced asset ratings to prepare for N-1.
- **Simple Curtailment Tool** (SCT) – this has modelled the effects of restrictions of Headroom at 132kV on the level of export from generation and storage. This model uses historic load flow data to include a representation of historic network outages

The curtailment output from the above analysis represents the network constraints related to only thermal and voltage limits. This informs the input for market model where the value of Headroom is evaluated. This Stage 1 analysis did not consider N-1 and unplanned outages which will be investigated in Stage 2 of the project. The method by which curtailment signals are sent to generators is outside the scope of the project.

The Network Model projection utilises data from the FES ST and the ECR to forecast the uptake rates of distributed generation across different network levels. Various seasonal profiles are modelled to capture peak demand and generation periods throughout the year, with specific attention to periods of high renewable generation coinciding with low demand. Profiles for solar PV, wind, gas, battery energy storage systems (BESS), heat pumps, and electric vehicle charge points are developed to represent their generation patterns across different seasons. The methodology also involves scaling from four peak days to 365 representative days for modelling purposes.

Following the modelling phase, the analysis evaluates the calculated net profiles for each feeder archetype and assesses curtailment levels across the entire distribution network. The analysis focuses on export constraints caused by voltage rise, thermal transformer, and thermal cable/conductor limits. The Network Model report[7] outlines the process of calculating curtailment and scaling from individual feeders to the whole system. Additionally, the curtailment is distributed to each technology type based on the proportion of generation.

The SCT was developed by NGED to support curtailment forecasts within Active Network Management (ANM) zones. The methodology assesses the baseline loading and adjusts net export profiles of generators to ensure compliance with network thermal limits. Generators are added using a Last-In-First-Out sequence, with consideration given to their proximity to network constraints. The tool iteratively calculates permissible exports to prevent constraint breaches, generating 'ideal profiles' and 'curtailed profiles' for each generator to maintain network stability. In this study, we assume all generators in the LIFO stack will connect. This will lead to higher DNO curtailment output which is useful for understanding the higher end of the impact. When considering the actual amount of contractually agreed connection generators, the curtailment output would be less significant.

The output of the SCT offers a more comprehensive approach to curtailment forecasting than the existing industry-standard approach; it considers multiple constraints, firm or alternative connection agreements and considers technology type and half-hourly generation profiles. It was applied to four Grid Supply Points that are in the largest 25% GSPs by installed DER capacity in GB in 2023.

5.4.2 Scenario design

This section aims to describe the three modelled scenarios and explain how to interpret the system cost outcomes. A summary is presented in Table 2.

Table 2: A summary of modelling scenarios

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

The counterfactual, which aligns with standard Baringa projection in 2023 Q3, assumes no curtailment is experienced in the distribution network, and this provides a baseline for comparison against the two other scenarios. The simulation uses the Baringa PanEU Day-ahead dispatch model, which represents not only the GB market but also interconnected markets across the Pan-European region. This reflects the continental interlinkage and allows for the best assessment of the impact. As described above, the Baringa NZH scenario is used because it aligns well with the FES ST scenario which the curtailment analysis is based on.

The two scenarios that represent headroom constraints are defined as 'Network Curtailment Scenario' which is based on Network Model input, and the 'Maximum Constrained Generation' scenario which is based on SCT input.

The curtailment referred in this report, based on the simulation data, only considers the network constraints related to thermal and voltage limits. ANM or any other manual constraints are not included.

There is a significant distinction in curtailment volume between the two scenarios. This is largely attributed to the difference in methodology adopted by the Network Model and SCT. The Network Model data represents a country-level curtailment condition with simplification and aggregation of the network architypes and voltage levels. Only LV, HV and EHV level data feeds into the simulation. Therefore, the result only captures a portion of the network curtailment representing mainly summer-period solar PV. Simulation based on this 'Network Curtailment' provides the estimated lowest level of curtailment.

The SCT output implies a high-level constraint in generation output to the network due to simplification and limited site selection. The analysis has assumed all LIFO stack would be connected and there is no additional headroom investment. This provides the highest potential constrained level for generators and is used to capture the upper range for the sensitivity test. The output is not a forecast for all new connections. Simulation based on this 'Maximum Constrained Generation' provides the estimated highest level of curtailment.

5.4.3 Representation of Headroom in the Baringa model

5.4.3.1 Network Curtailment scenario

The 'Network Curtailment' scenario draws its curtailment volume parameters from the Network Model simulation data.

The initial processing of the Network Model data involved several key steps:

1. **Technology Level Assessment:** The Network Model dataset has generation, curtailment, and percentage curtailed on an hourly basis for simulation years (2023, 2028, 2034). The data for each technology in scope is presented (solar PV, onshore wind, gas, and BESS). Generation is stated as generation available in the absence of a network constraint. Curtailment is calculated as the reduction of generation required to avoid constraints due to thermal and/or voltage limits. Percentage curtailment is calculated as the percentage each generator type that would be reduced compared to a hypothetical non-constrained generation level to avoid thermal and/or voltage limits.
2. **Voltage Level Aggregation:** For each technology, both generation and curtailment data were aggregated to three voltage levels (LV, HV, EHV).
3. **Mean day profile:** For each technology, a generation and curtailed volume profile was derived for every month. The profile takes the average volume (generation and curtailment) across 28-31 days for each hour within a day and is used to represent the general daily condition. The methodology is designed to allow the curtailment simulation to reflect the Network Model data pattern while preserving the original weather profile variability in power market model.

The Network Model data only has curtailment data during summer months, specifically from June to August. Simulated curtailment profiles for the four technologies for the statistically mean day in July 2034 are illustrated in Figure 12. The peak in curtailment volume is consistently observed between P12 to P15 (1200 to 1500) which aligns with the midday period and is characteristic of typical solar curtailment. It is worth emphasising that this pattern persists despite the distinct generation profiles of the other technologies, showing the dominance of solar PV curtailment during these hours.

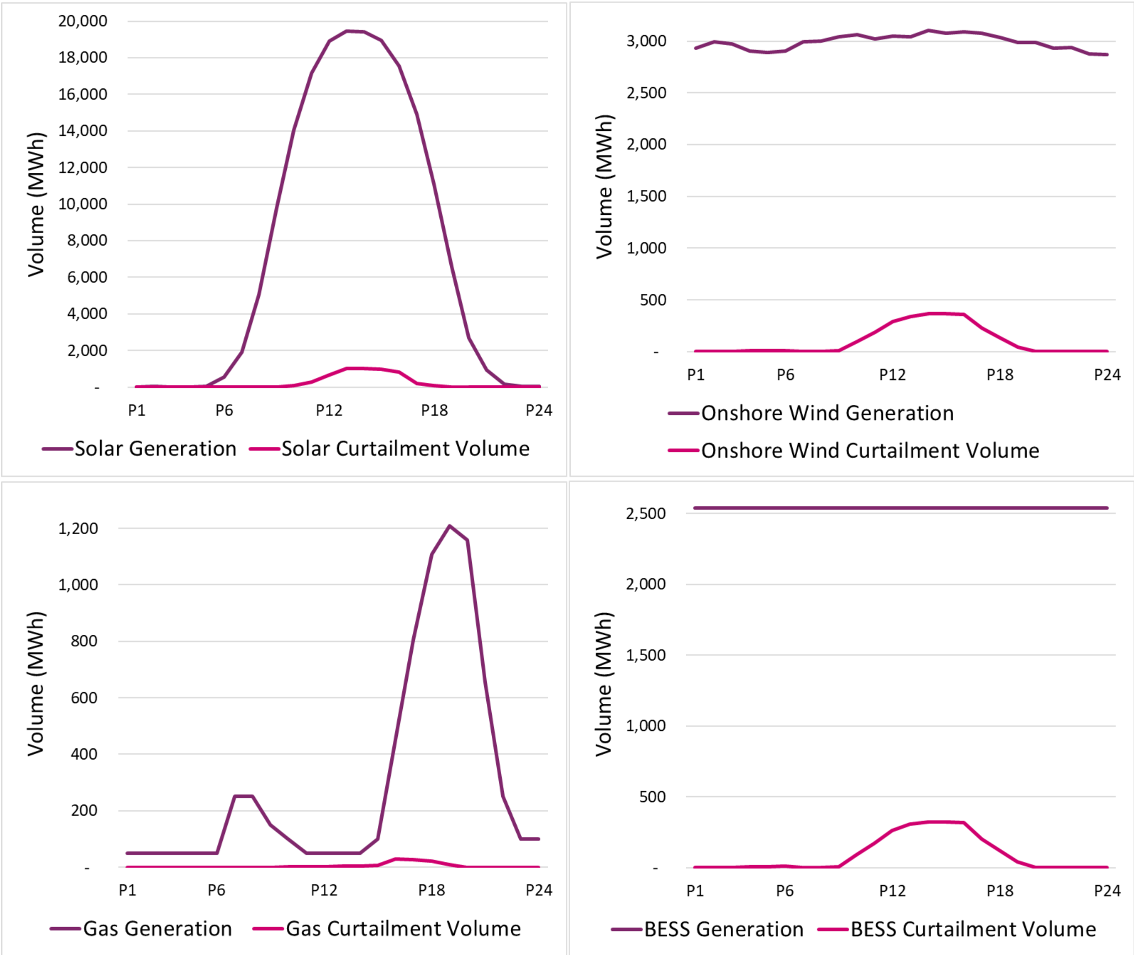


Figure 12: July 2034 mean day - Network Model aggregated curtailment and generation volume dataset

To represent the curtailment in renewables in the market model, PLEXOS onshore wind and solar generators' input profiles were derived. The market model assumes there is no offshore wind generation connected directly to the distribution network. Other transmission-connected generation capacity is kept the same as compared to counterfactual. The detailed steps for deriving the RES profile are outlined below.

1. **Baringa's RES hourly profile as a base:** The market model simulates the renewables generation with an hourly profile calibrated using the 2017 typical weather year. This profile provided the counterfactual, and the impact of network curtailment on renewables was subtracted.
2. **Alignment of Curtailed Volume:** The total Network Model curtailed volume was scaled to ensure consistency and alignment between Baringa NZH generation and FES ST generation.
3. **Distribution of Network Curtailment:** Technical curtailment was appropriately distributed in a generation-weighted manner across relevant time periods to accurately reflect thermal and voltage network constraints. The curtailment is only applied to distribution connected generators.

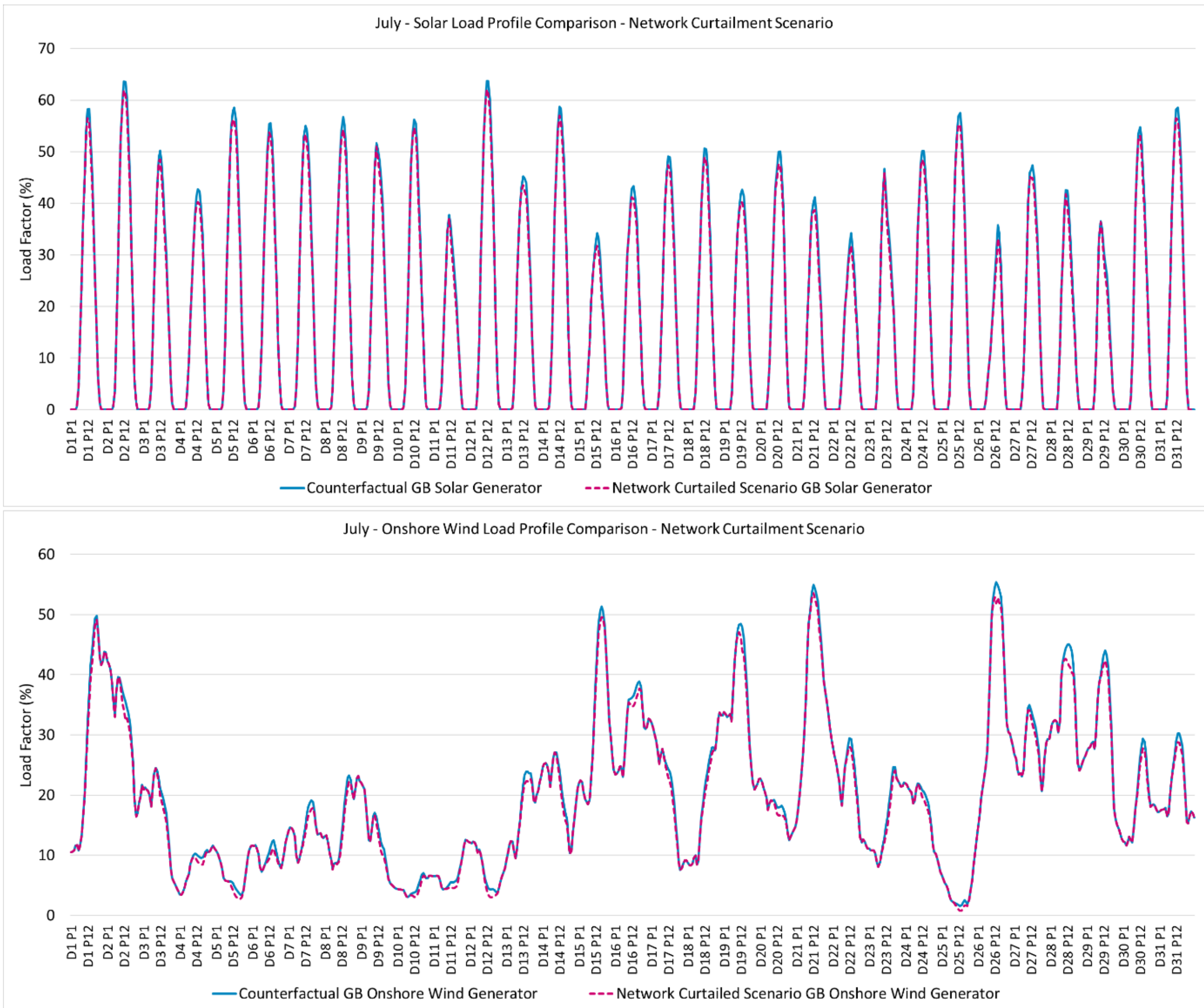


Figure 13: July 2034 - RES Comparison of Load Profiles, Network Curtailment[15]

The modified profiles, reflecting the integrated curtailment data, are compared to the original counterfactual profiles in Figure 13. This comparison focuses on a specific GB solar generator and a GB onshore wind generator, both for July 2034. This highlights the impact of the curtailment implementation on the generation patterns of the generators.

For gas and BESS curtailment, the limitation of generation export is applied for all hours and is relative to the assets' maximum capacity level. This is because these assets have the flexibility to dispatch against market prices and there cannot be hourly matching with Network Model data. The period when these flexible assets dispatch at high level should align with the time when system has limited capacity, reflecting high demand or low renewables generation.

The detailed implementation methodology is described below:

[15] All Figures in section this section 5.4.3 use day of the month (D1, D2, … where D1=1st, D2=2nd, etc) and the hour (P1, P2, …; where P1=00:00-01:00, P2=01:00-02:00, etc).

1. **Maximum curtailment level:** Based on the "Mean day profile" for each month (as illustrated for July 2034 in Figure 14, the maximum curtailment percentage of generation is derived for gas and BESS.
2. **Limitation on distribution-level Gas/BESS Generators:** Constraints are imposed on the distribution-level gas/BESS generators in the market model. The maximum generation export level of these generators is reduced by the maximum curtailment percentage for each month.

The methodology is illustrated in Figure 14 and Figure 15, highlighting the impact of gas and BESS curtailment implementation.

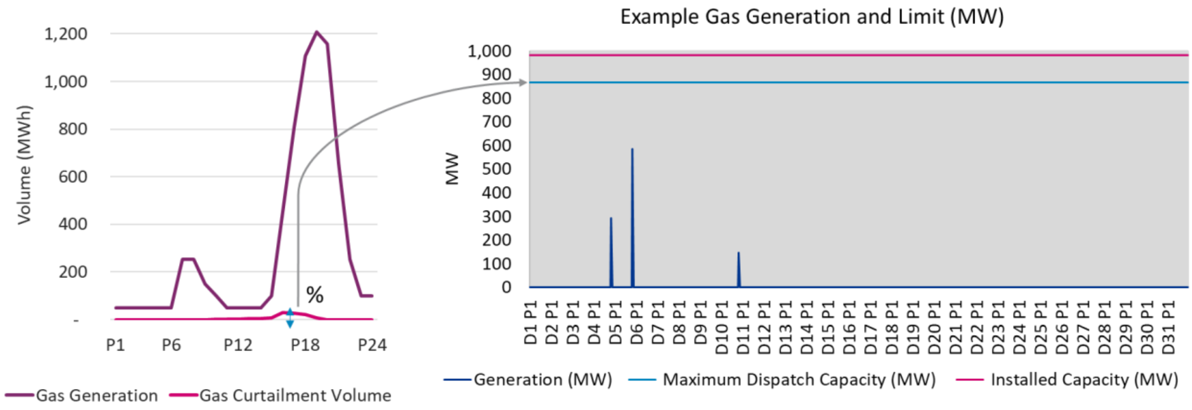


Figure 14: LHS: July 2034 average day gas generation and curtailment, Network Model. RHS: July 2034 gas generation and export limit, Network Curtailment

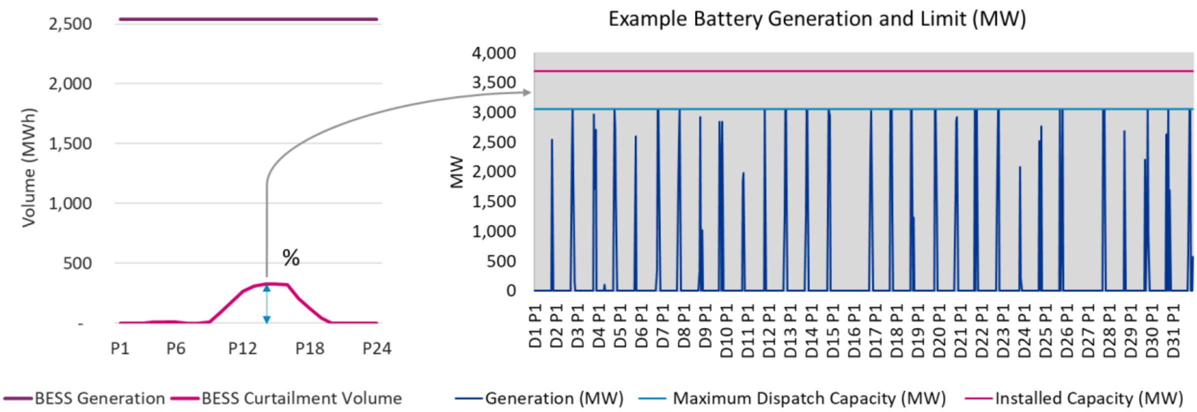


Figure 15: LHS: July 2034 average day BESS generation and curtailment, Network Model. RHS: July 2034 BESS generation and export limit, 'Network Curtailment'

In Figure 14, the Installed Capacity of the gas generation is scaled down by the maximum gas curtailment percentage for the day (blue arrow) to produce the Maximum Dispatch Capacity. Similarly, in Figure 15, the Installed Capacity of the BESS is scaled down by the maximum BESS curtailment volume for the day (blue arrow) to produce the Maximum Dispatch Capacity.

The adjustment of the installed capacity to 'Maximum Dispatch Capacity' models a limitation on the asset's ability to dispatch power to the grid and is applicable for asset dispatch in all hours in particular month. Given the flexibility of these assets, this method reflects better how these assets are likely to be curtailed in the market.

The Network Model dataset is constrained by its focus on curtailment volumes exclusively during June to August, reflecting peak solar PV generation. However, it overlooks curtailment during other seasons and the potential curtailment of onshore wind.

5.4.3.2 Maximum Constrained Generation scenario

This section focuses on the 'Maximum Constrained Generation' scenario, which draws the volume of generation and export constraints from the SCT simulation data. The simulation is specifically for the year 2034. As compared to the 'Network Curtailment' scenario, the 'Maximum Constrained Generation' scenario extends its scope to encompass the thermal and voltage network constraints for all months of the year.

In the text below (for reporting purposes only), constraints in generation and export in SCT data is referred as “curtailment” to compare against the Network Model results simulated by the Market Model. However, the volume does not reflect any real curtailment condition. The data is prepared based on a simplified method which capture the maximum possible level of generation turn down due to excess exports on the distribution network.

There is a notable difference of the curtailment volume and pattern between the data in the SCT and in the Network Model. This meant that the methodology for PLEXOS input preparation varied between the two scenarios to best mirror the data specific features. Processing of the SCT data followed a similar procedure as Network Model except data was aggregated by GSP instead of Voltage level in the second step:

1. **Technology Level Assessment:** The SCT dataset has generation, curtailment, and percentage curtailed on half-hourly basis for simulation years 2034. The data for each technology in scope is presented, namely solar, onshore wind, gas, and BESS.
2. **GSP Aggregation:** For each technology, both generation and curtailment data were aggregated across the four simulated GSP.
3. **Mean day profile:** For each technology, a generation and curtailed volume profile was derived for every month. The profile takes the average volume (generation and curtailment) across 28-31 days for each hour within a day and is used to represent the general daily condition. The methodology allows the typical feature of curtailment to be captured.

Figure 16 illustrates the SCT output in the 'Maximum Constrained Generation' scenario for July 2034.

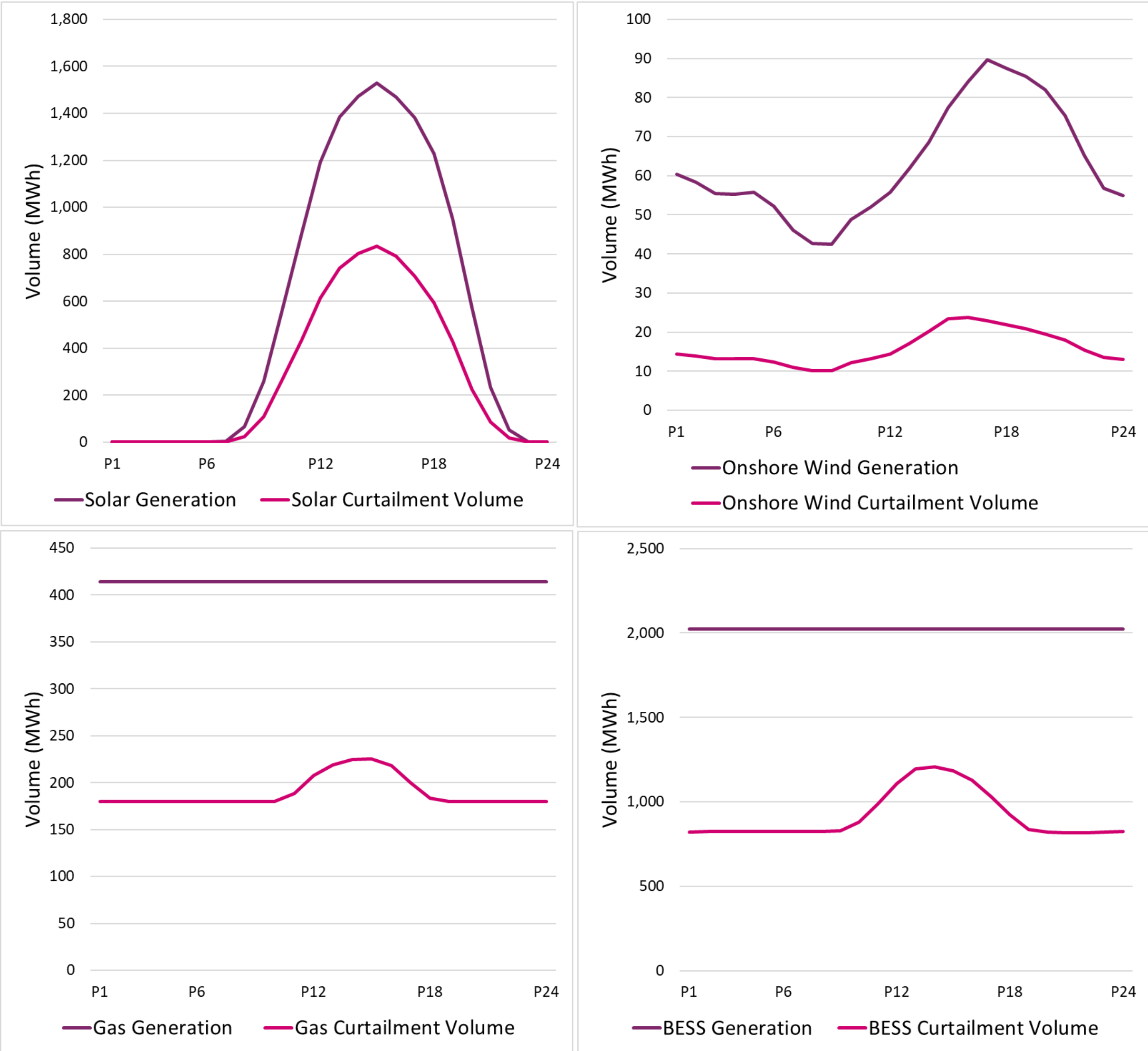


Figure 16: July 2034 mean day, SCT aggregated curtailment and generation volume dataset

This data is aggregated in the same method outlined in section 5.4.3.1. As can be seen, there is a significant difference in curtailment volume as a proportion of generation when compared to Figure 17 in the 'Network Curtailment' scenario. For solar, 35%-55% of the generation is curtailed due to thermal and voltage network constraints, and for wind it is 25%-40%. As the generation for gas and BESS is represented as a constant value, the curtailment pattern mirrors the solar pattern experiencing the highest constraint during mid-day. The high percentage level is designed on purpose to reflect the maximum impact, with the underlying assumption of all LIFO connection, no further headroom investment, high capacity GSP. This does not reflect the prediction of how much new connection may be curtailed in 2034.

Figure 17 illustrates the situation for January 2034, illustrating the seasonal variation in curtailment shape within the SCT simulation output. The solar curtailment is significantly reduced to 24%.

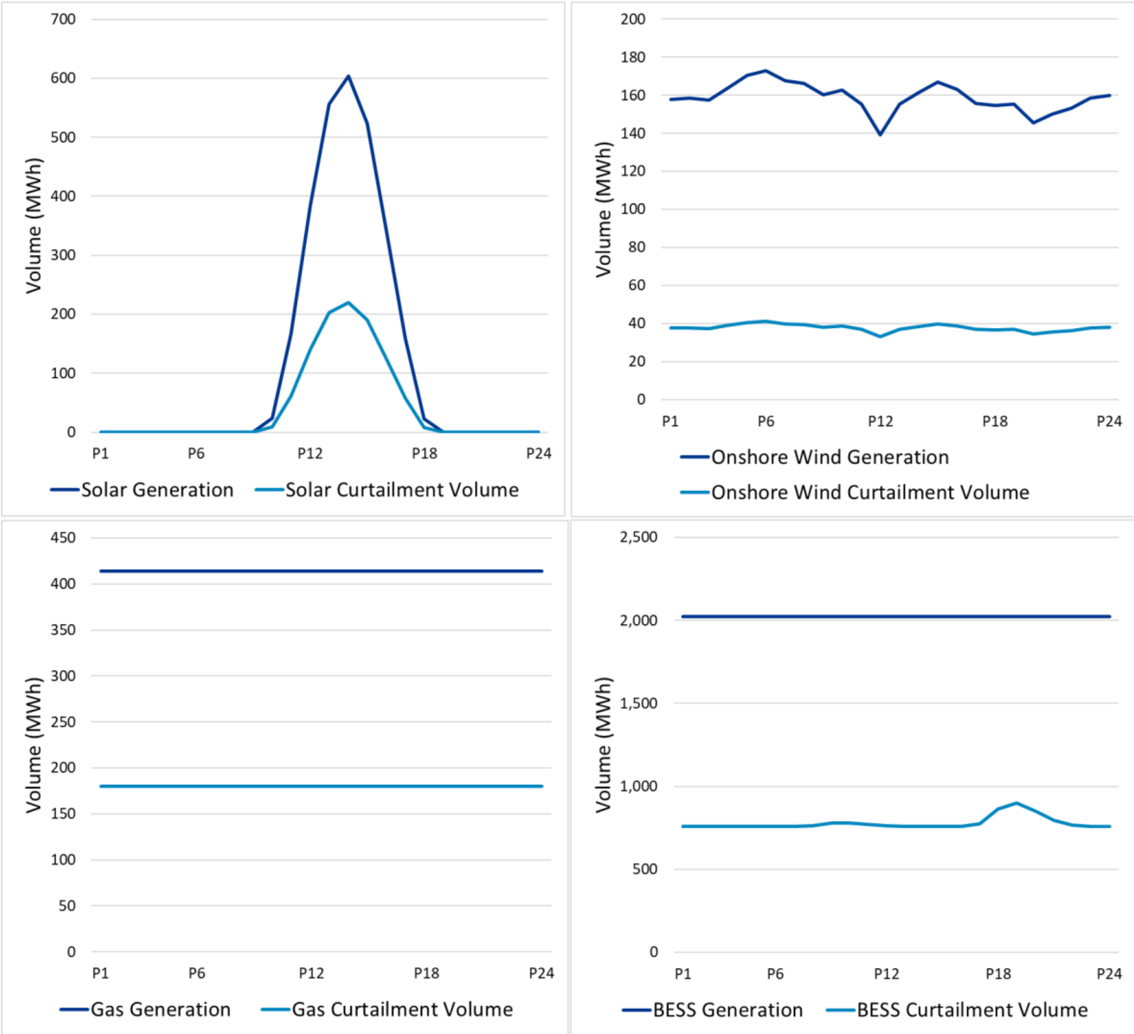


Figure 17: January 2034 mean day, SCT aggregated curtailment and generation volume dataset

Following this aggregation, profiles which determine the hourly generation of wind and solar generation are derived. To adjust RES profiles for the 'Maximum Constrained Generation' scenario:

1. **Constrained Export Percentage:** Based on the monthly typical-day average pattern, the constrained percentage level for each hour within a month is derived for wind and solar respectively.
2. **Application to Counterfactual Profile:** This constrained percentage is then applied to the counterfactual RES profile on hourly basis.

Figure 18 and Figure 19 displays examples of the modified RES profiles for solar and onshore wind in January and July 2034. Note that in the Baringa market model, the displayed renewables generator has a combined capacity for transmission and distribution level. The percentage of curtailment is only applied to the distribution level capacity, and therefore this illustration shows a T-D capacity weighted average adjustment of SCT data adjustment.

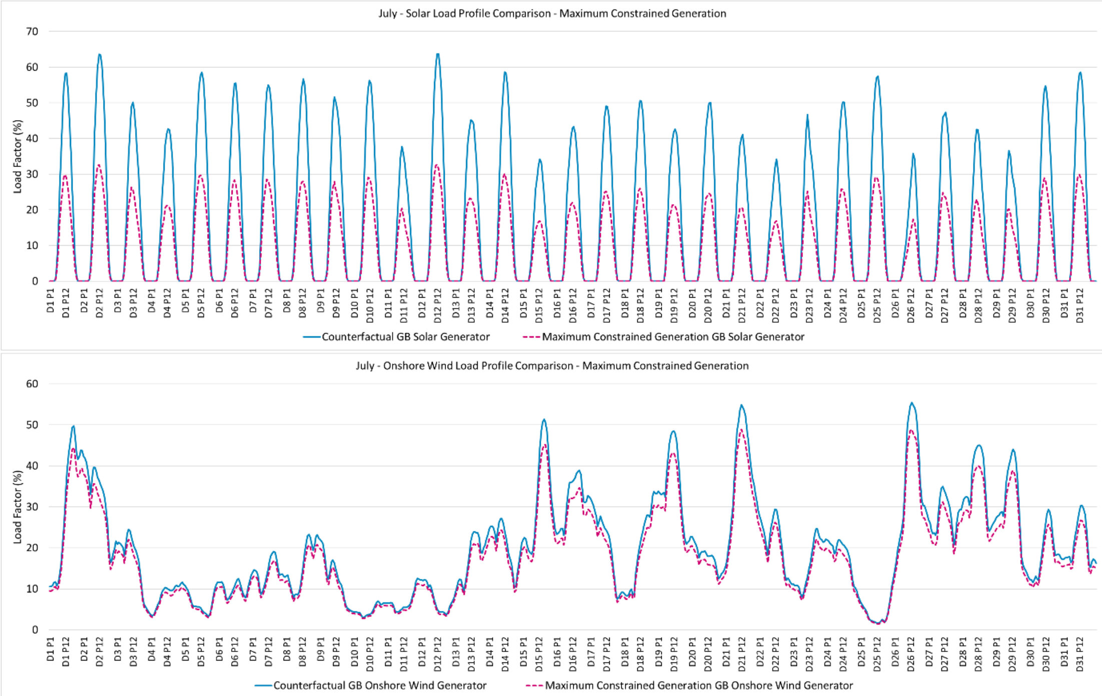


Figure 18: January 2034 RES Comparison of Load Profiles, Maximum Constrained Generation

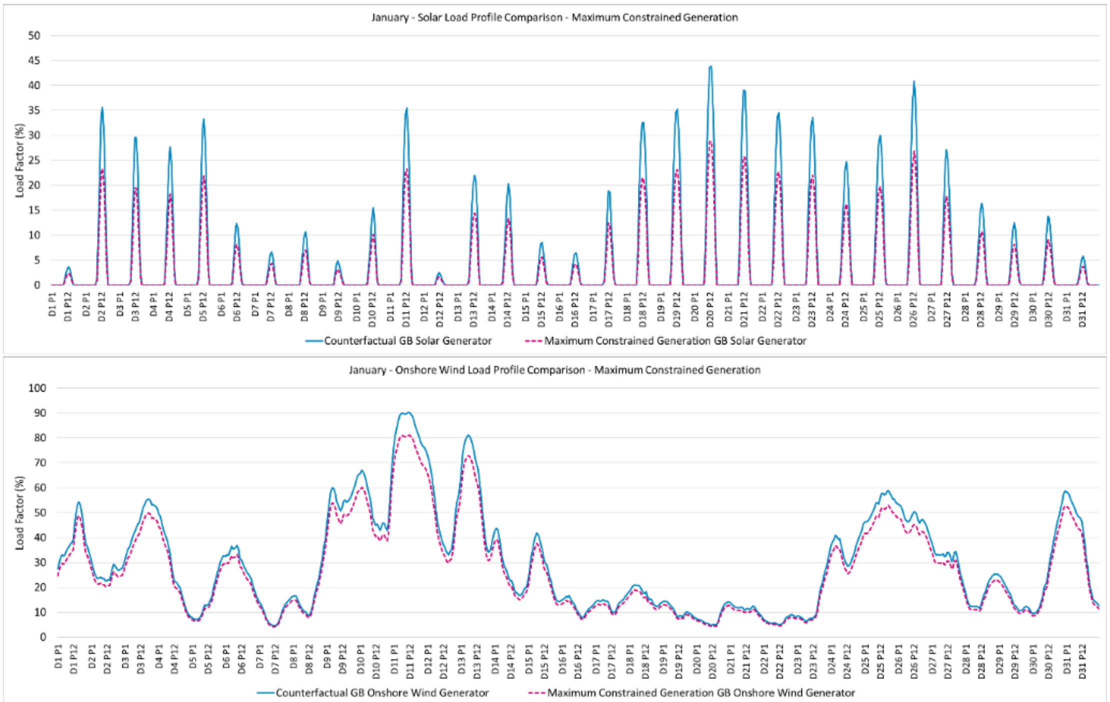


Figure 19: July 2034 RES Comparison of Load Profiles, Maximum Constrained Generation

For gas and BESS curtailment, the implementation of generation constraints into the PLEXOS model follows the similar methodology as in "Network curtailment" scenario. The process is outlined below and illustrated in Figure 20.

1. **SCT maximum percentage curtailment:** From the SCT output, the maximum percentage of curtailed versus simulated generation for an average day in each month is calculated.
2. **Maximum Dispatch Capacity:** Constraints are imposed on the distribution-level gas/BESS generators in the market model. The maximum generation export level of these generators is reduced by the maximum curtailment percentage. This applies to the generation of these assets for all hours throughout the year.

Note the SCT curtailment data shows BESS output constraints range from 40 – 65% and gas 40 – 60%. The level is rather high due to the SCT simulation limitation. Applying these constraints set a relatively severe limitation, which forms the upper limit of flexible assets' dispatch under network constraint.

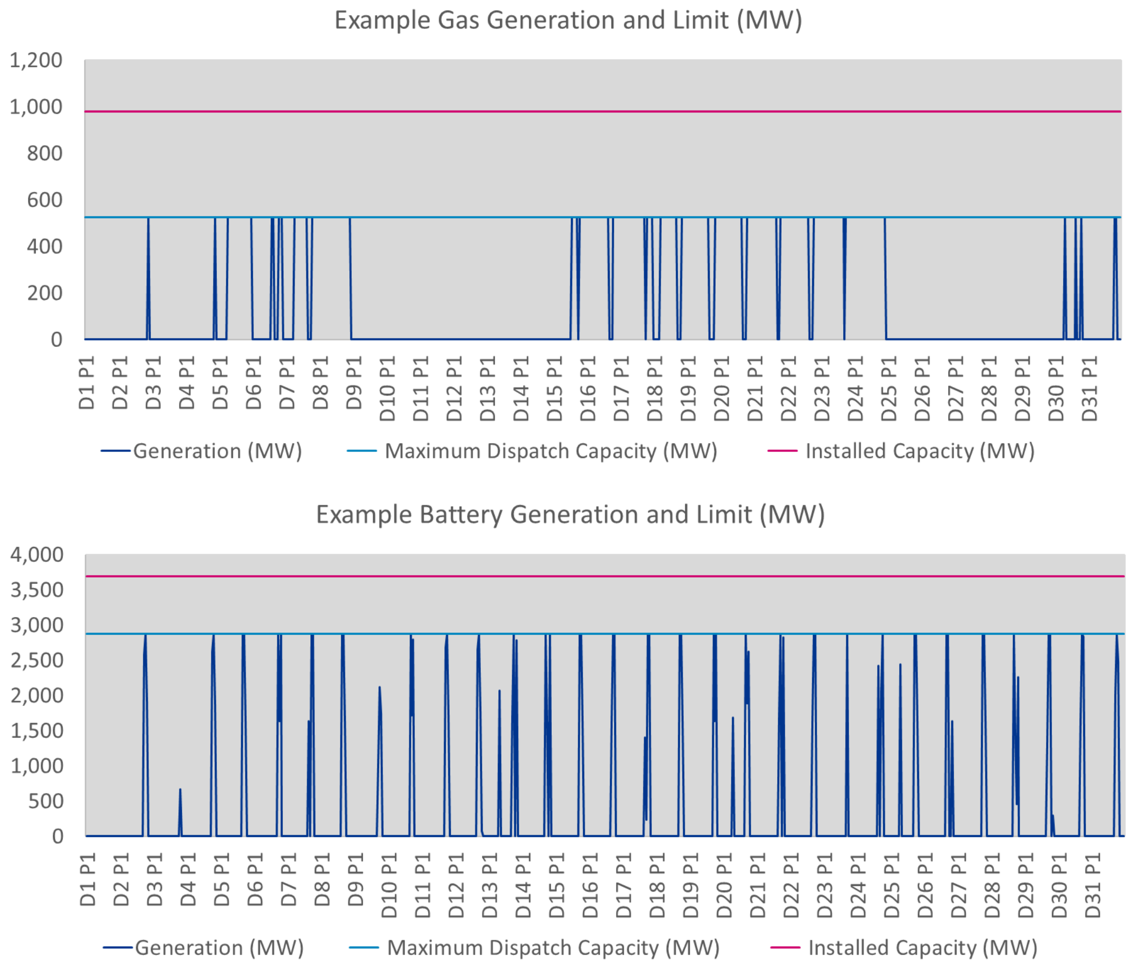


Figure 20: January 2034 gas and BESS generation and export limit, Maximum Constrained Generation

5.5 Headroom impact on generation

5.5.1 High-level description

Distribution network Headroom is defined in section 4 as the unused capacity available on a DNO asset enables an increase in generation (at minimum demand, maximum generation times) or an increase in demand (at minimum generation, maximum demand times) from the existing level. Headroom is modelled on four representative days: Peak Winter Demand, Peak Summer Generation, Peak Intermediate Cool Demand, and Peak Intermediate Warm Demand. The output Generation and Demand Headroom is used to manage the allocation of capacity to new connections and the dynamic nature of demand and generation means the available Headroom will have a profile throughout each representative day and throughout the year.

Storage assets (BESS and ECVPs) are unusual assets as they can influence Headroom negatively if they were to charge during a Winter Demand Peak or discharge during a Summer Generation Peak. However, they can also improve Headroom, e.g. a BESS could charge from solar PV generation to reduce the Peak Summer Generation, enabling greater renewable generation whilst remaining within the available Headroom. Similarly, EVCP could discharge EV batteries to reduce the Peak Winter Demand, enabling greater demand whilst remaining within the available Headroom. Unfortunately, the use of a BESS and / or ECVP in these circumstances may not increase Headroom if system studies have not been revised to reflect this.

5.5.2 Renewables

In this section, the analysis will examine the outcomes for renewable generation in both scenarios, the 'Network Curtailment' scenario and the 'Maximum Constrained Generation' scenario.

Figure 21 presents the result for 'Network Curtailment' scenario, with the details for onshore wind and solar generation volumes during summer months. The difference between the counterfactual and the 'Network Curtailment' scenario increases over time, with 2034 exhibiting the largest disparity. This reflects the increasing level of curtailment simulated by the Network Model. By 2034, total simulated curtailment reaches 400 GWh for solar and nearly 1,000 GWh for onshore wind. This accounts for 3.8% and 5.6% for the total solar and wind generation, in corresponding months. This amounts to 1.5% and 1.2% respectively when compared to total annual generation levels. Among the three months of summer, June experiences the largest impact. The Network Model curtailment simulated follows the pattern for solar PV generation and this scenario may not capture the further curtailment of wind during winter peak periods.

Figure 21: Monthly (June-August) RES generation in the counterfactual, Network Curtailment

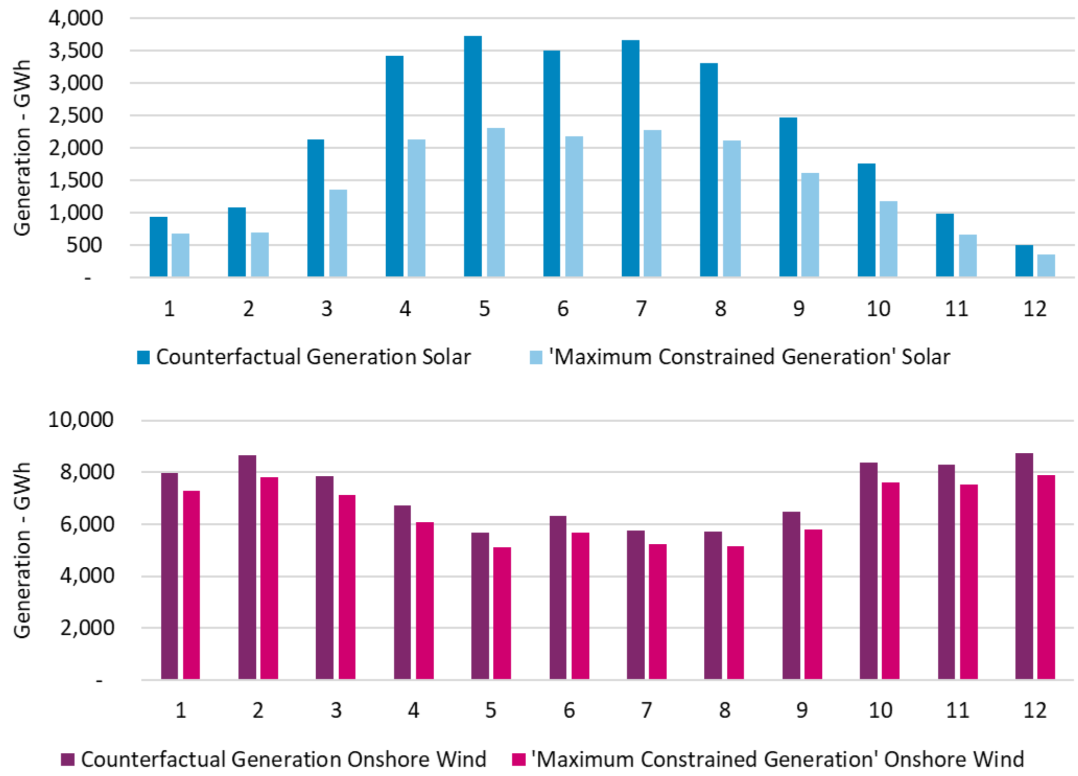


Figure 22: Monthly RES generation in the counterfactual, Maximum Constrained Generation 2034

In Figure 22, a substantially greater curtailment volume was incorporated, extending across all months. Additionally, there's a distinct difference in the curtailment patterns between solar and onshore wind, contributing to a more realistic representation. Figure 22 provides a comparison of generation volumes between the counterfactual and the 'Maximum Constrained Generation' scenario.

Table 3 provides a summary of the curtailment volumes for both scenarios, along with contextualisation against the counterfactual generation. This comparison underscores the relative difference in curtailment implemented in between both scenarios. The results highlight the sensitivity of the largest range of potential headroom impact. Neither end should be interpreted as the predicted outcome for future network operation condition.

Table 3: Summary of RES curtailed volumes, both scenarios

		'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%

**These years only aggregate June to August, as that is the effective curtailment period in the 'Network Curtailment' scenario*

5.5.3 Thermal and BESS

In this section, the analysis will examine the impacts on gas and battery generation in both scenarios. The max export limit is illustrated in Figure 23 and Figure 24Figure 20, where hourly dispatch of these flexible assets are constrained.

Figure 23 depicts the gas generation comparison for ‘Network Curtailment’ scenario.

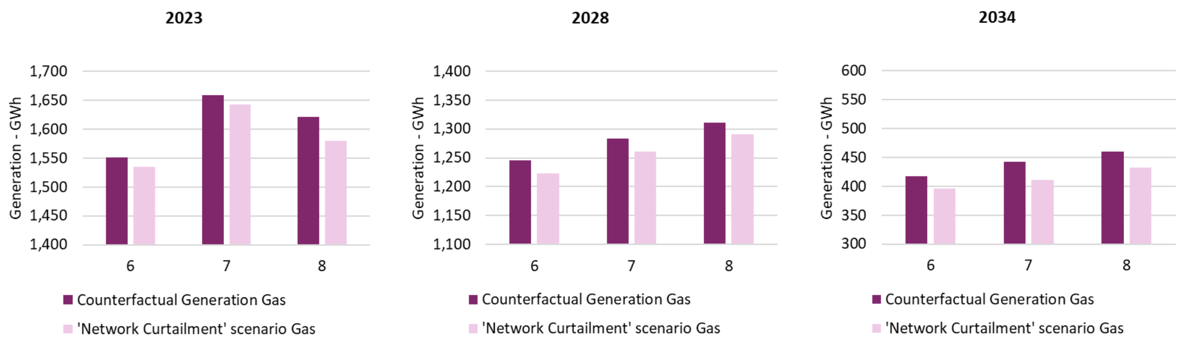


Figure 23**: Monthly (June-August) of gas generation in the counterfactual, Network Curtailment**

Figure 24 shows the constrained gas generation for the ‘Maximum Constrained Generation’ scenario. Throughout the year, the maximum curtailment occurs during January when there is high demand and renewables generation, especially solar PV, is limited. The annual curtailment level, due to the high limitation based on SCT data, equates to ~10 TWh.

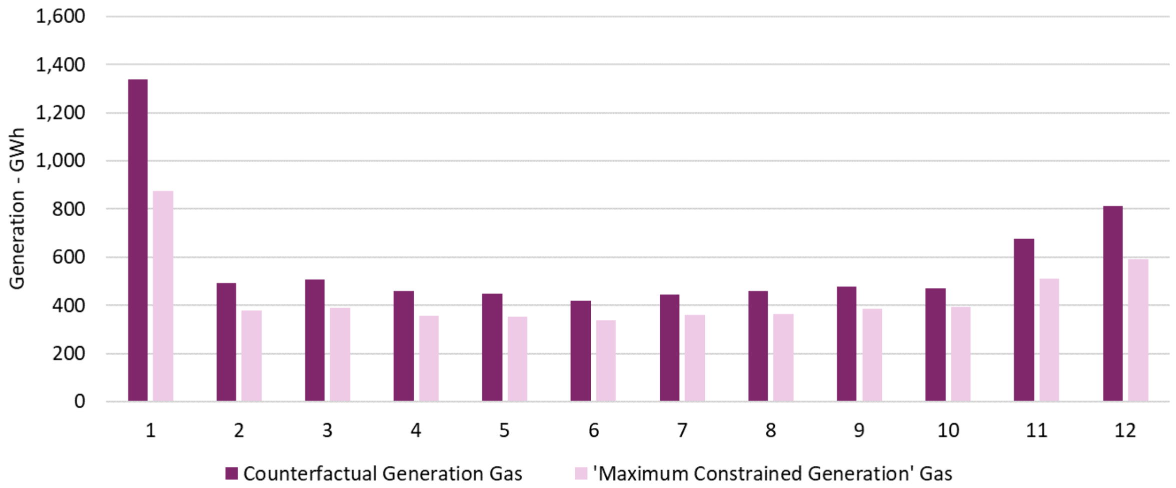


Figure 24: A monthly view of gas generation in the counterfactual, Maximum Constrained Generation 2034, all months

The curtailed volume, as summarised in Table 4, ranges between 60 – 85 GWh by 2034. The volume accounts for 6% of monthly distribution-level gas generation. However, relative to the annual level, that is only around 1% as most of these gas generation happen during the winter season.

Table 4: Summary of gas curtailed volumes, both scenarios

		'Network Curtailment' scenario			'Maximum Constrained Generation' scenario
		2023* Jun - Aug	2028* Jun - Aug	2034* Jun - Aug	2034
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%

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

For batteries, though there are export limit imposed in the model, we do not set constraints on charging and storage size. Therefore the overall generation volume stays relatively similar between counterfactual and curtailment scenarios.

5.6 System impact analysis

5.6.1 System cost comparison

This section provides an overview of the outcomes from each simulation, focusing on the impact in system costs, changes in emissions, and variations in imports and exports.

Table 5: A summary of the system cost impact for both scenarios.

		'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

		'Network Curtailment' scenario (Jun-Aug of each year)				'Maximum Constrained Generation' scenario
		2023*	2028*	2034*		2034
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*

In brief, the system cost is the customer load multiplied by the wholesale price. The difference between the counterfactual run and the scenarios provides the system cost impact due to Headroom. The summary table for both scenarios is presented in Table 5, and Figure 25 illustrates the value derivation across the time horizon assuming linear interpolation.

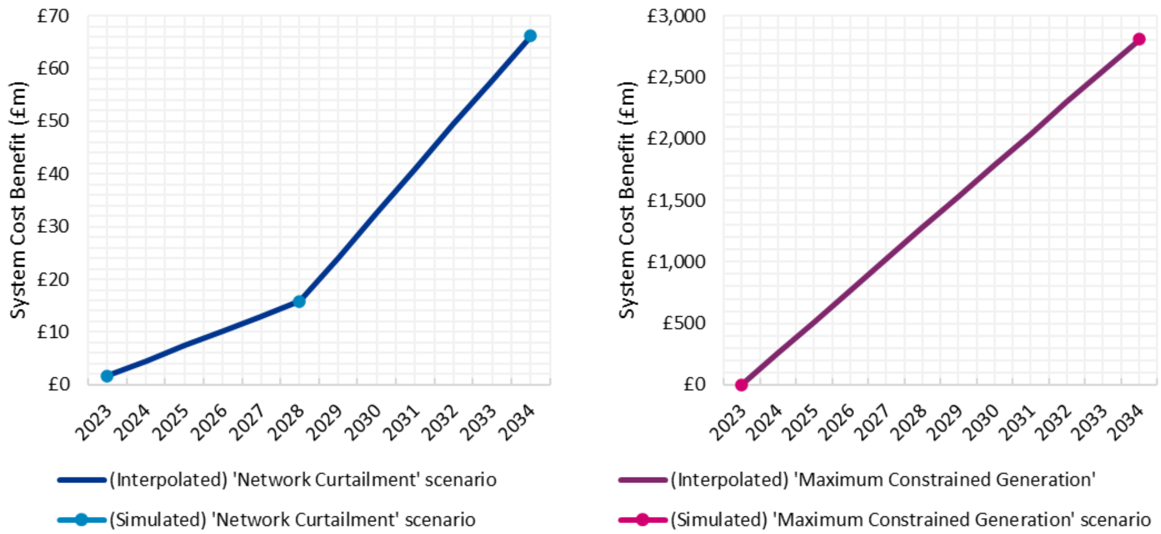


Figure 25: System cost benefit for both scenarios with linear interpolation applied from 2023 to 2034

For the 'Network Curtailment' scenario, we present the system cost benefit only for the summer periods, when Network Model curtailment occurs. As the market model simulates not only GB, but also European markets within a single optimisation framework, the change in GB generator availability will influence the scheduling across Europe for different seasons. This introduces additional differences between the counterfactual and curtailed scenarios. To ensure the consistency for cost comparison, only June to August cost difference is considered as there should be no impact during other months.

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).

5.6.1.1 Seasonal Price Impact

This section analyses the seasonal impact, presenting price differences for both scenarios in absolute and percentage terms (relative to the counterfactual price).

For the ‘Network Curtailment’ scenario the price differences show a consistent annual upwards trend; 2034 exhibits the largest seasonal variance of ~1% (Figure 26) with a monthly price increase of £0.50/MWh to £0.94/MWh (Figure 27).

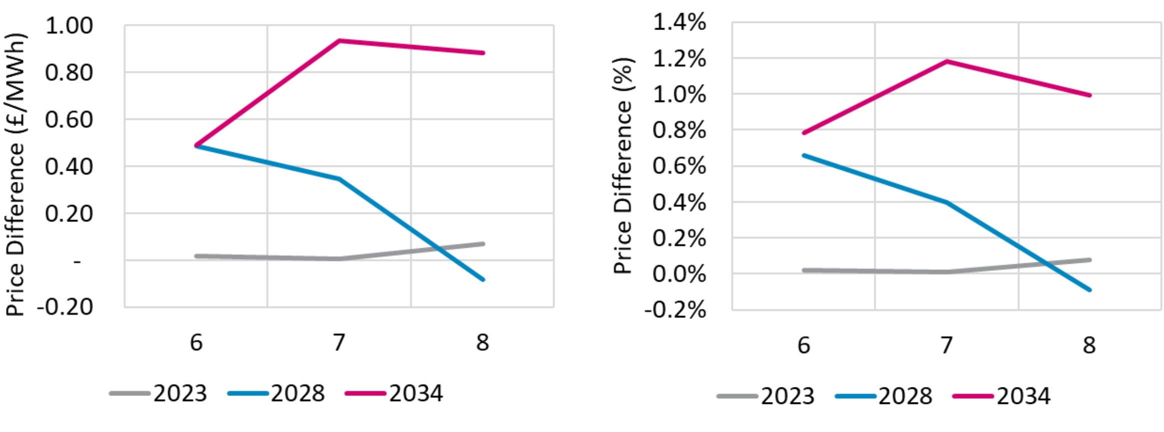


Figure 26: Monthly price difference, 'Network Curtailment' scenario (versus counterfactual)

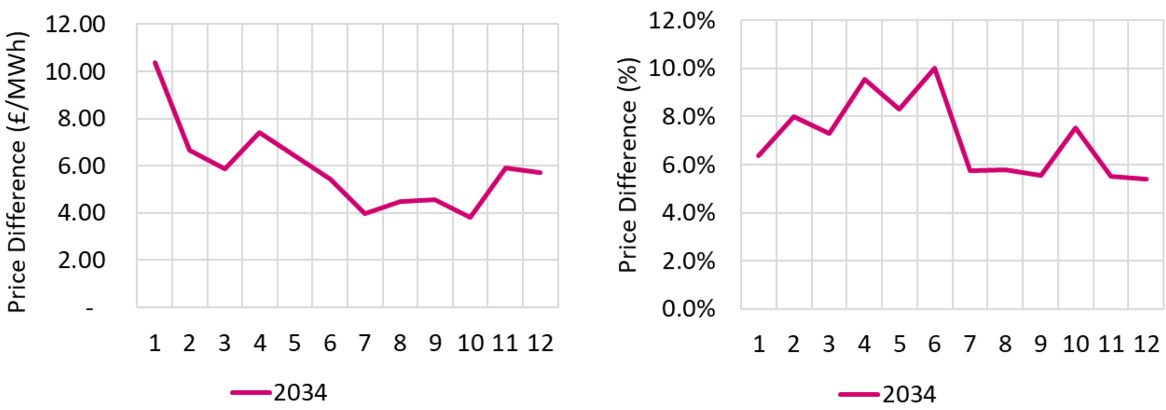


Figure 27: Monthly price difference, 'Maximum Constrained Generation' versus counterfactual

In Figure 27, the price difference in 2034 ranges between £4-10/MWh on monthly basis, ~6% of the total price. The highest difference is observed during January when the system has little generation margin with high demand and limited solar PV generation. Throughout the year, the most significant relative difference observed during April to June, corresponding for periods with good conditions for both wind and solar PV generation.

5.6.1.2 Price Impact at High and Low levels

This section explains the details, on an hourly price level, what the potential impact of curtailment is. We focus the discussion on 'Maximum Constrained Generation' scenario. This is because the curtailment effect in this scenario is more widely observed across the whole year in different periods, while the 'Network Curtailment' scenario only experiences limited impact during summer mid-day period.

Figure 28 compares the price duration curve with the counterfactual. A price duration curve plots electricity prices over a specific period. Prices are ranked from the highest to lowest and are displayed on the y-axis, and the x-axis plots the duration (in hours) of the corresponding price levels. The curve serves as a tool to analyse the price distribution within a given year.

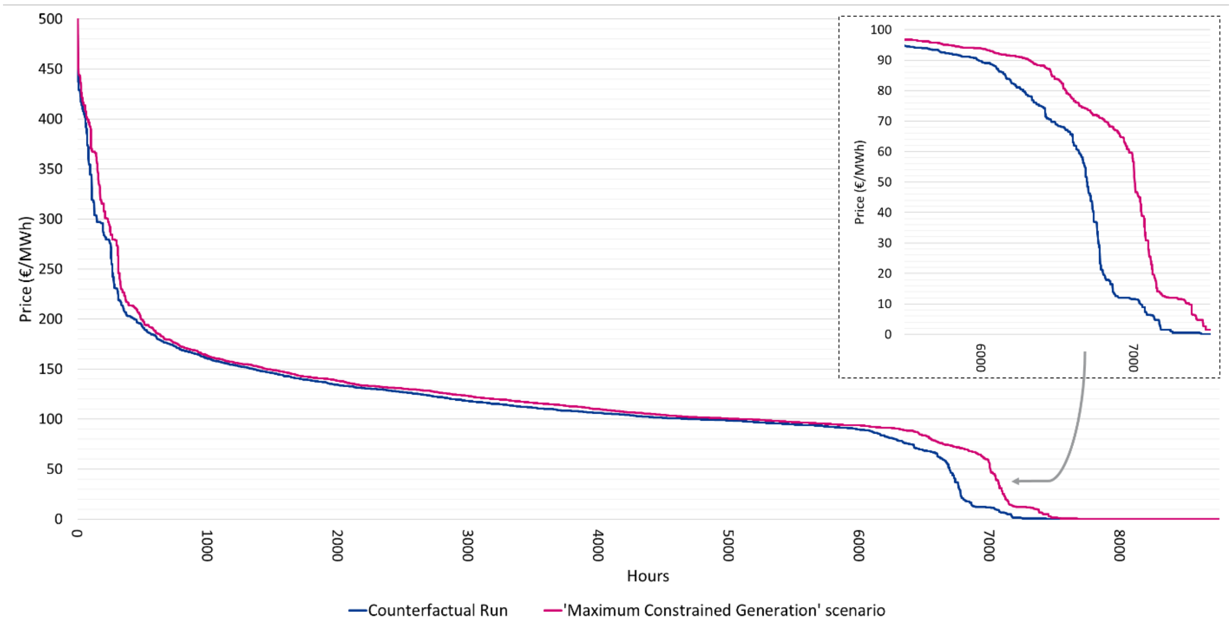


Figure 28: Price Duration Curve comparison - 2034

On the left side of the curve, the hours with a higher price are typically set by more flexible gas assets with smaller capacity and lower efficiency. The 'Maximum Constrained Generation' scenario displays prices that are further right implying a greater number of hours with marginally higher pricing. This behaviour is largely attributed to the constraints on distribution-level gas generators which cannot export at full capacity to the network. As a result, more expensive gas generators need to be dispatched, which increases the market price. The constraint on import is around 50% for these distribution-level generators, a considerable proportion of capacity. However, the result shows a relatively moderate impact. This is due to many more transmission-level gas generators which have similar efficiency level but can operate more flexibly and competitively to mitigate the price rise. Nonetheless, there are additional 50 hours of high price above £200/MWh when the generation faces significant constraint in this scenario. This, compared to the 440 hours in Counterfactual, is a 10% increase and could result in potential wholesale market stress.

At the right side of the curve, a larger difference is noticeable between the 6,000-7,000 hour mark, which has been magnified for clarity. This discrepancy is associated with constraints on RES generation. We observe fewer zero-price hours in the 'Maximum Constrained Generation' scenario; with less renewable availability, other generators with higher marginal cost need to dispatch to meet demand and set the price above zero. In total 1,074 hours are projected at zero price in the 'Maximum Constrained Generation' scenario, ~300 hours less than the counterfactual.

5.6.2 System carbon comparison

This section examines the impact on the system's carbon output for both scenarios, relative to the counterfactual. Curtailment of the system's RES generation results in an increase in generation by more carbon-intensive technologies, driving the system's carbon output higher. The relative impact is limited due to gas generation constraints and the similar efficiency level of transmission-level gas generators.

The impact is summarized in Table 6. Aggregated over the 12-year period (and using linear interpolation), the overall impact on system carbon cost is ~£116m with an average annual impact of ~£10m for the 'Network Curtailment' scenario. For the 'Maximum Constrained Generation' scenario, the overall impact is ~£753m with an average annual impact of ~£63m.

The magnitude of impact is significantly more pronounced in the 'Maximum Constrained Generation' scenario. For 2034, a simulated impact of 0.79 million tonnes is projected, representing an almost 16-fold increase compared to the 'Network Curtailment' scenario for the same year. This is due to the largely constrained RES availability which lead to more thermal generation with high carbon emission. This results in an impact on system cost of around £125.5m.

The emission which could be avoided through headroom relief will 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[16].

Table 6: Summary of system carbon impact for both scenarios.

		'Network Curtailment' scenario				'Maximum Constrained Generation' scenario
		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

** Assumption on CPS becomes 0 beyond 2030 (based on Baringa Net-Zero High projections)*

5.6.3 Net GB import impact

In this section, the focus is on presenting the impact on GB import and export, specifically within the framework of the 'Maximum Constrained Generation' scenario.

[16] Lifecycle emission assumption based on BNEF Electric Vehicle Outlook 2021 for UK

Figure 29 shows the changes in GB cross-border power flow, with positive values denote export volume and negative values indicate import volume.

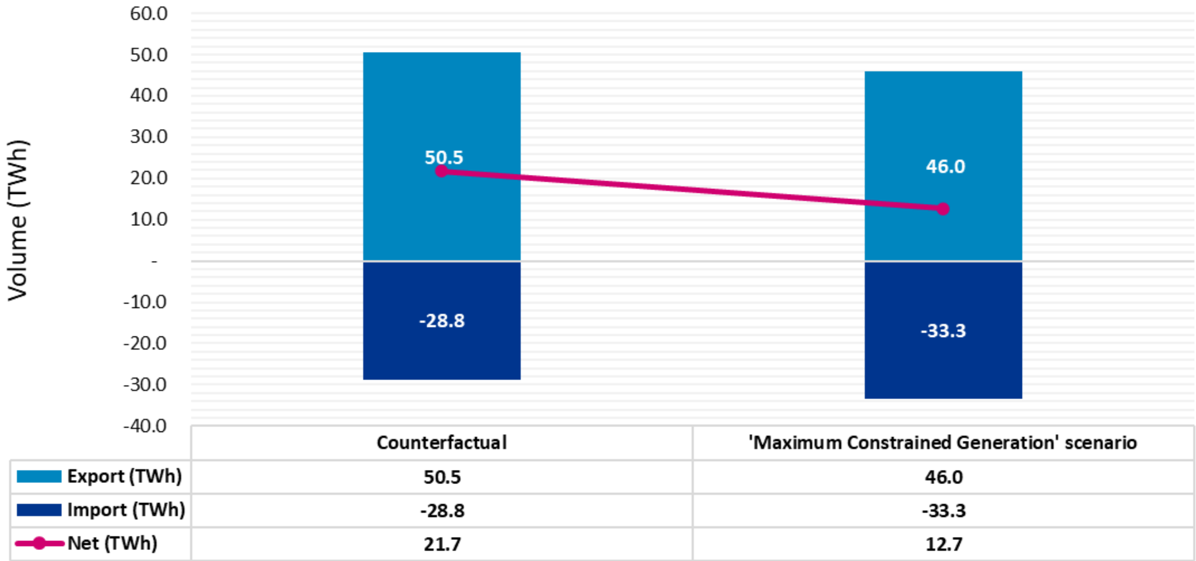


Figure 29: A comparison of the import and export volumes for the counterfactual run versus the 'Maximum Constrained Generation' scenario run

When comparing the counterfactual to the 'Maximum Constrained Generation' scenario, a noticeable reduction in export is observed, from 50 TWh/year to 46 TWh/year, due to a reduction in low-cost RES-generated electricity. The volume of imports also rises, showing a higher reliance on neighbouring market during high price hours. However, GB remains a net exporter in both scenarios.

Constraining RES generation leads to an increase in power prices, diminishing the incentive for export, hence the reduction in export volume. Similarly, the decrease in the availability of dispatchable gas and BESS generators in GB drives a rise in import volume. This reduced availability necessitates a greater reliance on importing electricity from neighbouring markets during periods of system strain. The need for increased imports is also driven by the elevated costs of the remaining, more expensive, domestic generation sources.

This projection of GB being a net exporter in 2034 aligns with the projection outlined in the FES ST, which indicates a net export volume flow of 61.1 TWh for the same year.

5.6.4 BM imbalance impacts

The BM Energy Imbalance Cost has a large variation depending on the weather conditions. Historically, the annual cost between 2019 and 2023 varied between £6m/year to over £100m/year. There were also months when ESO had positive revenue to balance the system, up to ~£10m/month. However, the cost relative the Day-Ahead market is very small when compared to the total wholesale market (~£100m compared to £40 billion, ~0.25%). In addition to the Day-Ahead wholesale market, the impact of distribution-level curtailment is also assessed for the Balancing Mechanism (BM). The Baringa BM market model is used to simulate the energy balancing behaviour in the GB market.

Only the "Network Curtailment" scenario is simulated as the constrained generation in the "Maximum Constrained Generation" scenario is far greater than the total volume cleared in the BM. This section will focus on the "Network Curtailment" scenario only.

The hourly curtailment level used in Day-Ahead market is used to model onshore wind and solar PV in the BM Model. Similarly, the maximum generation level applied to gas and BESS in the Day-Ahead market is used to limit the redispatch behaviour of these flexible generators in the BM Model.

Table 7: 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 National Grid ESO*

The simulation focuses on the energy balancing action in BM only. Transmission constraint management, which is presented in the next chapter, is not included here.

The simulation result shows the level of impact at around -1.2% to 0.4% for the three selected years which implies the potential change in BM imbalance cost at the magnitude of less than £1m/year.

With less renewables in the system, the imbalance level which relates to the forecast error of these generators, would be less. Therefore the system cost to re-balance demand would reduce. From the supply perspective, both counterfactual and curtailed scenario, distribution-level RES generators would not have the capability to offer additional generation into the BM. The constraints on them to export at maximum availability will therefore have no impact on how the system clears.

Though there are limitations in gas and BESS generation level, due to the high available flexible asset capacity and small volume of imbalance, the impact could be relatively negligible.

The ESO has committed to removing barriers for distributed flexibility to participate in the BM. This includes allowing generators with an individual capacity of less than 1 MW, most of which are connected to the distribution network, to participate in the BM as part of an aggregated unit. While this would unlock the balancing capability of these generators, this means that any headroom constraints on the distribution level would hamper the benefit of this additional flexibility. The system cost impact would be more material if the change is implemented.

6 Balancing services impacts

6.1 Context

The modelling and analysis in section 5 considers the impact that constraining DERs has on their ability to participate in the wholesale electricity market. In addition, DERs connected to a constrained part of the distribution network would be limited in their ability to offer Balancing Services to the ESO, or services to the DNO.

To assess the potential impact of headroom constraints, we need to consider:

1. **What is the value** associated with balancing services, and the cost that is ultimately passed to end consumers?
2. **Which ancillary services** would we expect DERs to be offering into the electricity system?
3. **How might Headroom limit the ability of DERs** to participate in these services, whether because of technical restriction or because of eligibility rules?
4. **If those DERs are unable to provide the services, what would be the impact** on the costs that the ESO and end consumers would have to pay for those services?

This chapter introduces the main ancillary services in which DERs can participate and which technology can provide each service. This service-technology mapping will serve as the basis for estimating maximum values of the financial and environmental benefits provided by an increase in Headroom for Stage 2 and Stage 3 of the project.

6.2 Balancing Services expenditure and customer impact

The ESO procures Balancing Services to balance demand and supply and to ensure the security and quality of electricity supply across Britain's transmission system. Analysis of the balancing services usage over the last 13 years[17] highlights a seven-fold increase in total cost, driven by two factors:

- Constraint Management costs, incurred when the ESO re-dispatches energy resources, due to a lack of sufficient transmission network capacity to move energy around the system, have increased from £169 million in 2010/11 to £1,779 million in 2022/23.
- Balancing Services costs were driven by higher commodity costs during 2021/22 and 2022/23 which increased these costs from £1,850 in 2020/21 to £4,149 in 2022.23.

This is summarised in Figure 30 and will, ultimately, be reflected in customer bills as balancing costs are recovered through Balancing Services Use of System (BSUoS) charges. Using the latest calculations for Ofgem's default tariff cap (November 2023)[18] provides an allocation of these charges into different components for a typical customer, as illustrated in

[17] Monthly Balancing Services summary (MBSS) | ESO (nationalgrideso.com) has data back to 2019; the remaining data is from Baringa archives.

[18] Energy price cap (default tariff) levels, Ofgem, November 2023

Figure 31.

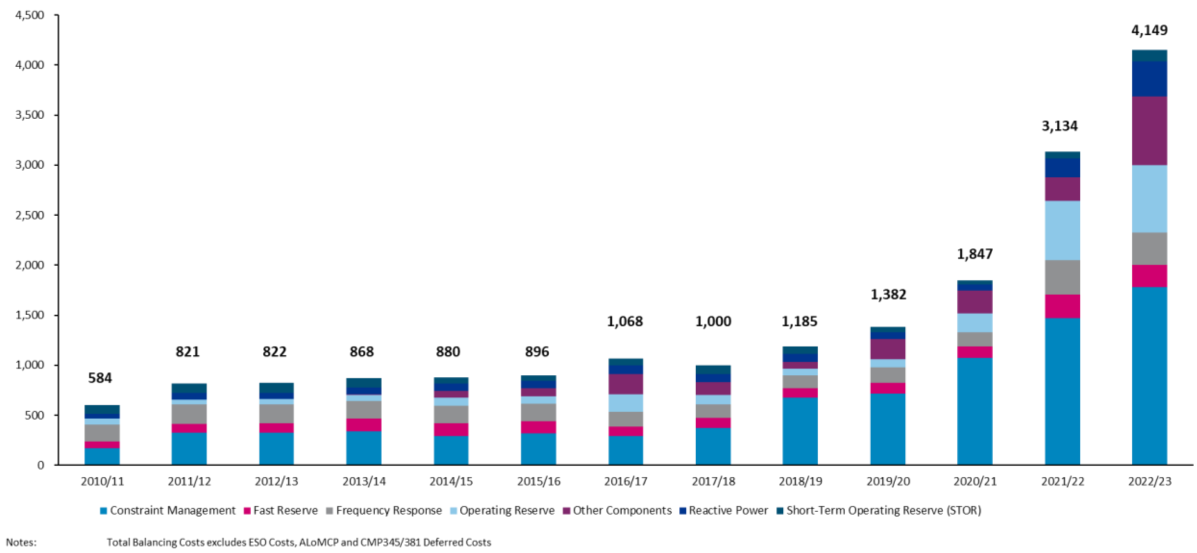


Figure 30: The total cost for Balancing the System in GB has increased significantly over time

The different price components in **Figure** 31 are defined by Ofgem and summarised below (the Wholesale Cost Allowance and Network Cost Allowance would each be impacted by a change in Headroom; the effect on other components is marginal):

- **Wholesale Cost Allowance** – the value of the Direct Fuel Cost Component using information on wholesale prices, backwardation costs and CfD costs. It also includes the Capacity Market Cost Component using information on auction clearing prices and obligated capacity. Together these allowances form the Wholesale Cost Allowance
- **Network Cost Allowance** - the sum of the Network Cost Allowance for electricity and for gas, using data from network companies' charging statements and assumptions about demand and losses.
- **Policy Cost Allowance** - the value of the Policy Cost Allowance, using forecasts from scheme administrators and assumptions about demand.
- **SMNCC** - the value of the Smart Metering Net Cost Change, using smart industry body charging statements and budgets, and the modelled allowance for non-pass-through costs.
- **Other Operating Costs** – the sum of the Operating Cost Allowance, excluding SMNCC, determined by Ofgem.
- **Adjustment Allowance** - the value of adjustments, based on Ofgem calculation methodology.
- **Finance Elements** – the value of EBIT and Headroom Allowance Percentage for suppliers, determined by Ofgem.

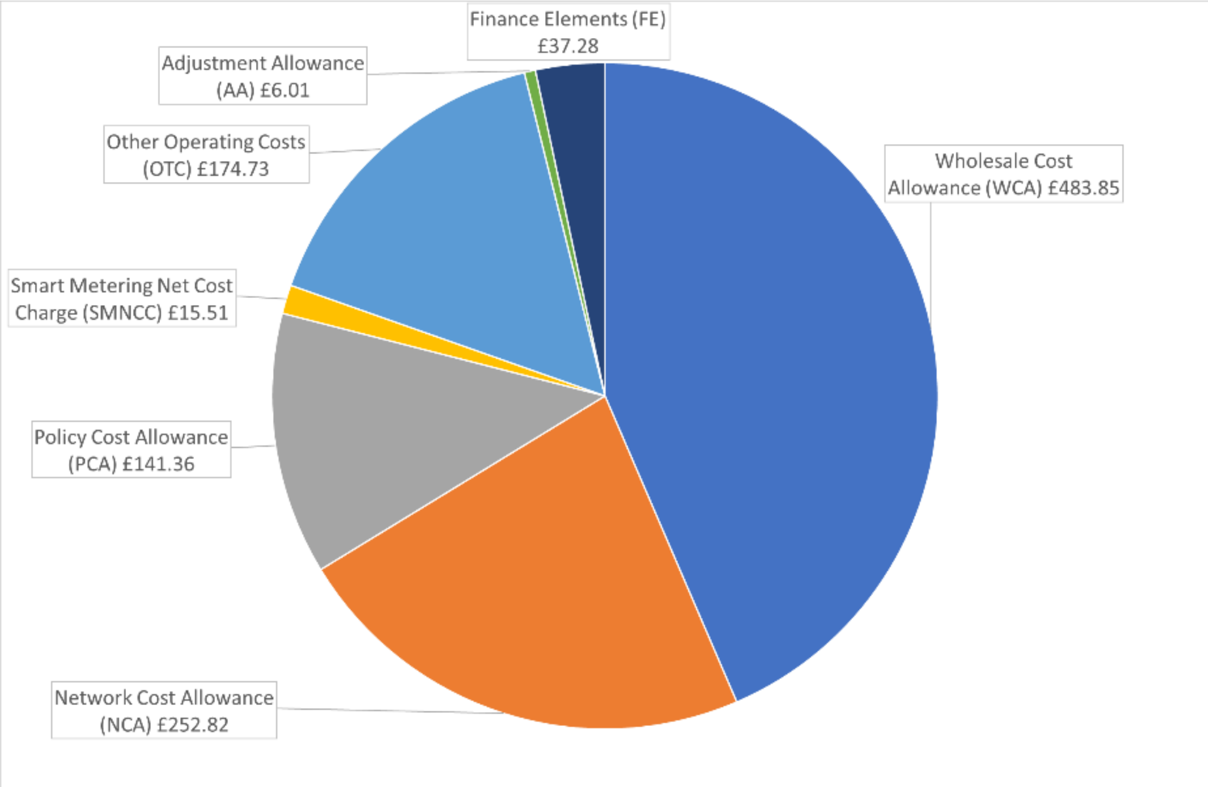
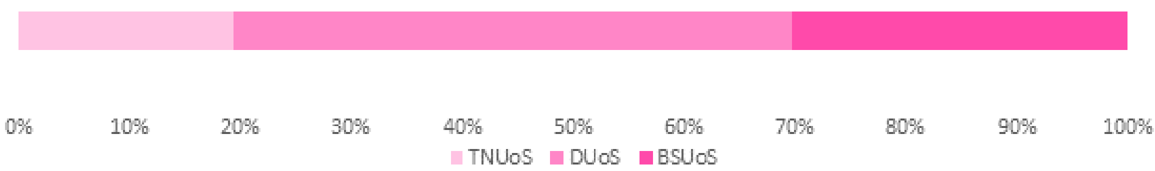


Figure 31: Typical electricity customer bill breakdown[19]

The electricity network costs can be further broken down into three components[20] and are illustrated in Figure 32:

- charges for transmission network use of system (TNUoS).
- charges for distribution use of system (DUoS); and
- charges for balancing services use of system (BSUoS).



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[19] Default Tariff Cap Level 1 January to 31 March 2024 model, Ofgem and Default tariff cap level 1 January to 31 March 2024 model, revised November 2023, sheet “ElecSingle_SC_3100kWh" for Electricity - Single-Rate Metering Arrangement (Standard Credit), January 2024 - March 2024, Southern Western region.

[20] Ofgem Energy price cap (default tariff) levels, Other Documents 1 October 2023 to 31 December 2023, Annex 3 – Network cost allowance methodology elec v1.16.xlsx, Tabs 2a-2c

Figure 32: Breakdown of annual electricity network costs

Together the Wholesale Costs and Network Costs represent 66% of the consumer bill and any changes to either component will affect the consumer bill. It is assumed there is no interaction between these two price components and other components of the electricity bill. In some cases, this may be a simplification, e.g. bidding behaviour in the Capacity Market is likely to be affected by participants earnings expectations in wholesale and other markets, but it is difficult to prove and is expected to have a marginal effect.

6.3 Estimated benefit of increased Headroom availability

The wholesale and network costs make up just over 66% of a consumer's annual bill in southern western area (**Figure** 31) and **Error! Reference source not found.** identifies these components as being impacted by a potential change in network headroom availability. Table 8 discusses the mechanism through which these each of these cost components is expected to be affected.

Table 8: Network headroom change impact on bill component

Bill Component	How Bill Component is impacted by change in distribution network headroom
Wholesale cost	Network constraints may prevent lower cost technologies from contributing to meeting demand during periods of constraints; demand is therefore met by higher cost alternative technologies with the cost difference being passed on to consumers.
TNUoS	An increased in distribution network headroom is likely to have secondary effects on reinforcement needs for transmission network ultimately reflected in the TNUoS charges. However, these effects are excluded from analysis at this point: we assume that any constraints on the transmission network is managed via balancing services.
DUoS	An increase in distribution Headroom may provide a benefit in three ways. It enables the connection of more low carbon technologies, including renewables which reduces the carbon footprint. It may reduce the need for DNO flexibility services. New connectees may be able to provide services to the DNO, ESO, and / or wholesale markets. The Headroom
BSUoS	In the absence of increased distribution network headroom, network constraints may prevent lower cost balancing service providers to participate in the balancing market. In this case, balancing services would be provided by higher cost alternatives with direct impact on the magnitude of BSUoS.

As shown in Figure 33, ~43% of Balancing Services expenditure (£1.8bn) is associated with addressing transmission constraints. However, collectively 23% was spent on securing reserve[21] (£962mn).

[21] Reserve Services includes Negative Reserve, Fast Reserve, Other Reserve, Operating Reserve and STOR.

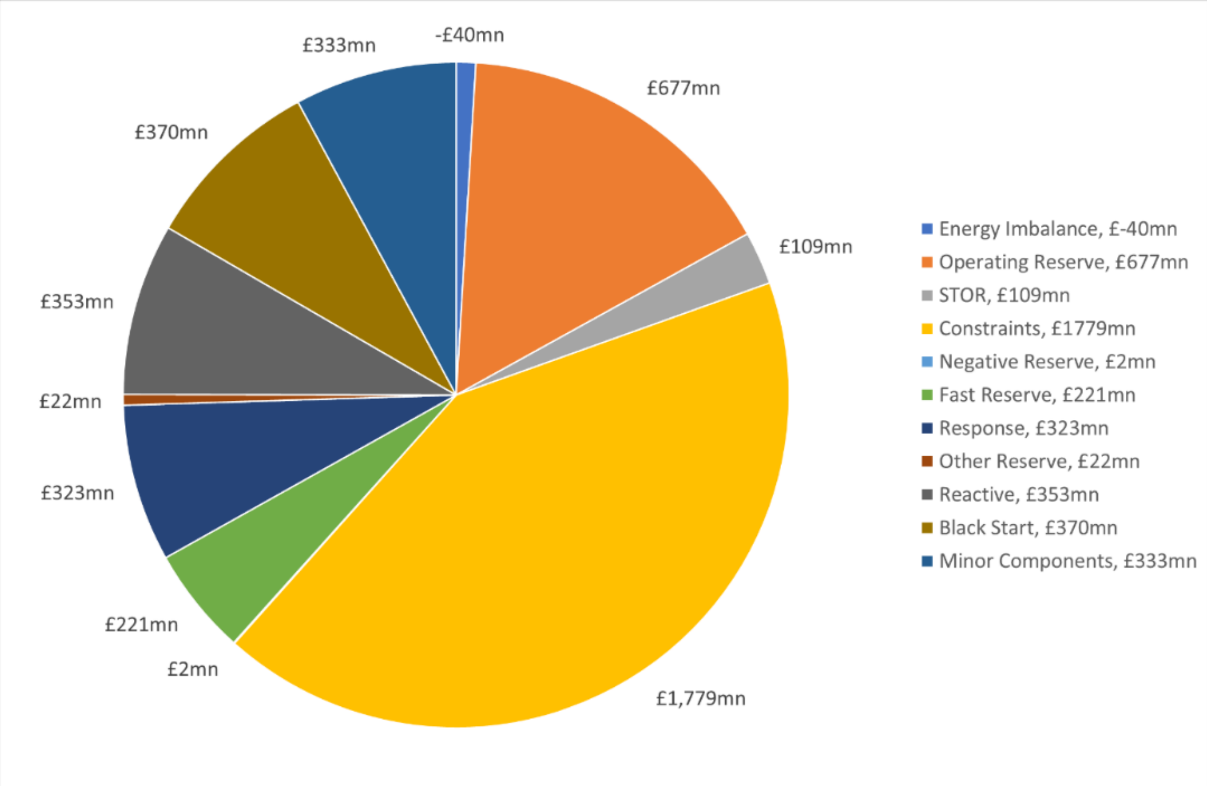

Figure 33 NGESO Balancing Services breakdown 2022/23[22]

The main issue is how an increase in headroom might be expected to affect the cost of each of these Balancing Services elements. Although Phase 1 will not model this impact directly, it is important to understand the mechanism by which Headroom increase could affect those costs. The impact will depend on when distribution assets are constrained (and to what extent), but also the rules governing their access to the various Balancing Services markets. Illustratively, there are two outcomes that bound the potential impact:

1. Headroom reduction leads to constraints on the distribution network in some seasons, on some days, and at certain times of the day. The ability of ESO to access Balancing Services from distribution-connected is limited ***only when those constraints are active***. At all other times, access is unfettered.
2. Although constraints only occur during certain periods, the inability of a distribution-connected flexibility provider to know and guarantee its availability means it is not able to offer the service ***at any time***, either because the asset is unable to connect in the first place, or because it connects under a timed connection with access only when the service is not needed.

[22] National Grid ESO, Monthly Balancing Services Summary, March 2023

In practice, we would expect the true impact to lie somewhere between these two extremes. Precisely where on the spectrum will depend on the nature of the service required, how far ahead of delivery a provider needs to commit, and how predictable a constraint might be. Another key factor is how a distribution constraint affects the connection of new generation assets. For example:

1. The lack of headroom may mean than a generator that would have connected chooses not to, e.g. it may decide that a timed or flexible connection is not suitable. In this case, the ESO never gets access to that asset's flexibility.
2. A generator may take a timed connection, which reduces or removes access during certain seasons, days, or hours where the network is at risk of constraint.
3. A generator may take an ANM-enabled connection, in which case it can technically access system services whenever the network is not constrained but may not be able to predict when constraints will limit this access. During a constraint, it may still be able to provide some services, but it will depend on how the ANM scheme is administered, and how it interacts with the ESO.

This last point about ANM systems may be key. ANM is the system by which the level of export from sites with flexible connections is managed. The ANM system monitors one or more nodes on the network that are at risk of being constrained and curtails those sites with flexible connections when there is a risk the network load could exceed its safe operating capacity.

NGED has already undertaken an NIA project[23] to understand how the design of ANM schemes and the Balancing Services market can be coordinated to minimise conflicts and maximise value. For this first phase we have opted to rely on the modelling carried out as part of that NIA project, noting that the project concluded in 2021, so may need to be updated as we enter Stage 2 of this work.

6.4 Key findings from Optimal Coordination of ANM project

The central hypothesis of the Optimal Coordination of Active Network Management Schemes and Balancing Services Market project was:

"… without coordination between the ESO and DNOs, there is potential for ANM schemes to counteract the ESO's balancing actions or to cancel out the effect of system services procured from Distributed Energy Resources (DER). This could lead to increased costs to the consumer and risk to security of supply if system services cannot be delivered when required. In addition, ANM systems need to be designed and operated in a coordinated manner during whole system emergency situations."

The investigation of this hypothesis and several of the key assumptions and outcomes from this report can support this Headroom project. The project closedown report[24] summarises the risks that ANM schemes can pose for participation in the Balancing Services market:

[23] National Grid - Optimal Coordination of Active Network Management Schemes and Balancing Services Market

[24] NIA_NGSO0035 Close Down Report (nationalgrid.co.uk)

- "**Risk of non-delivery by ANM generators:** ANM generators may be curtailed when called to provide Balancing Services, and as such could be exposed to non-delivery penalties (depending on the service).
- **Risk of unnecessary restrictions:** ANM generators could be unnecessarily restricted from participating in Balancing Services (a recent example being ODFM, which explicitly excludes ANM generators). Actual curtailment levels may be very low, and a generator may in theory be able to participate in the service with little or no impact on delivery due to ANM. This restriction on market liquidity could increase costs for consumers.
- **Counteraction risk:** Non-curtailable generators can provide Balancing Services, but NG ESO may see the effect of procuring services from such generators counteracted by an ANM scheme curtailing (or realising curtailment on) an ANM generator. The non-curtailable generator does not face non-delivery penalties, but the net effect is not that desired by the ESO, so services from other providers will have to be used, increasing consumer costs.
- **Risk of over-reaction:** In some instances, a generator ramping output to provide a Balancing Service may do so faster than an ANM generator can ramp down. In this case, the ANM system may have to trip the ANM generator entirely and allow it to come back on the system when it is safe to do so."

The project estimates the costs associated with a lack of coordination between ANM systems and ESO Balancing Service procurement. It notes that whilst the prevailing volume of ANM-connected capacity is small, it is expected to increase significantly in the future. Rather than using the absolute impacts, this project will use the £/MW impact for each generation technology considered:[25]

- Cost of bids being counteracted by ANM schemes:
  - "If accepted Bids from **1MW of wind** and **solar** were counteracted at times of ANM curtailment in 2019, the cost to consumers would have been **~£1.0k/year** and **~£1.3k/year** respectively.
  - If accepted Bids and Offers from **1MW of gas** were counteracted at times of ANM curtailment in 2019, the cost to consumers would have been **~£2.9k/year**."
- Cost of generators choosing not to participate to avoid non-delivery penalty risk:
  - "The benefit of an additional **1MW of wind and solar** participating in the BM would have been **~£3.3k/year** and **~£0.8k/year** respectively.
  - The benefit additional **1MW of gas** participating in the BM would have been **~£162k/year.**"
- These figures represent the cost associated with a lack of headroom assuming DERs are connected through ANM and that the action of that ANM system is not optimised for BM Service provision. The project recognised the potential for these costs to be reduced if coordination can be improved to avoid conflicts and allow DERs behind a constraint to participate without facing a risk of non-delivery penalties.

[25] Optimal Coordination of Active Network Management Schemes and Balancing Services Market: *WS1 & WS2 Report: Review of Current ANM Schemes and Development of Test Cases*; https://www.nationalgrid.co.uk/downloads-view/206443

- The technical report does indicate potential coordination savings of between £30m and £138m per year depending on the coordination method and the year being considered. However, this is not compared to a £m/year baseline, which makes it difficult to get an estimate of the range of costs that should be considered in this report.
- Balancing Services costs have increased since the Optimal Coordination of ANM project report was published but, for the purposes of Stage 1, these costs are conservative and provide a useful indicative value with an accuracy commensurate with other cost items without any revision.

7 Conclusion and Next Steps

7.1 Conclusions

This report has investigated the system cost and carbon saving associated with releasing Headroom on the GB electricity distribution networks to enable unrestricted use of DERs. This has been achieved with data from two curtailment models that determined the effect of constraints on DERs This data was used as inputs to the Baringa Pan-EU market model. The market model used the Baringa NHZ scenario which assumes ambitious decarbonisation targets and a high penetration of renewable generation to determine the benefits of releasing Headroom.

The output of the market model shows that releasing Headroom between now and 2034 could bring significant benefits for the GB system in terms of cost and carbon reduction:

- The accumulated system cost saving could range from ~£330m to ~£17bn between 2023 and 2034 (£27.5m to £1.4bn annually).
- The carbon emission which could be avoided through headroom relief will range between 0.7 Mt and nearly 5 Mt, which is equivalent to nearly 200 thousand electric vehicles' carbon saving over their lifetime
- The impact on wholesale price is between £0.70/MWh and £6.00/MWh, some of which may be used to reduce customer bills.
- The highest price impact would happen in January when the system has little generation margin with high demand and limited solar PV generation

The report also examines the impact of releasing the headroom on the BM. Due to the relative smaller market size, the impact is currently limited (less than £1million/year) due to the lack of participation by DERs. However, this could increase significantly as the ESO has committed to allow further participation of DERs below 1MW generators provided there is sufficient Headroom.

7.2 Next Steps

There is a wide range of annual benefit from releasing Headroom that varies from material (£27.5m) to significant (£1.4bn). It is proposed this project continues with Stage 2 to confirm the materiality of the benefits and to narrow the range from releasing Headroom through more detailed constraint modelling and the production of high-level price curves to represent the range of benefits.

This section identifies areas to be explored during Stage 2.

7.2.1 Estimation of Curtailment

- How to improve the evaluation methodology for curtailment and the level of granularity of calculations as they apply to all DERs.

- How to standardise the evaluation of curtailment across all voltage levels.
- The extent to which the outputs apply to all DNOs and DERs.
- Explore a range of assumptions around DSR and local storage.
- Explore how Headroom could better promote low carbon consumption during periods of low carbon grid intensity.
- Refine the outcome of network curtailment simulation to represent the impact in different seasons, especially during winter period. This will allow market model assessment to capture impacts when system is tight and higher cost generation is required.
- Refine the outcome of network curtailment simulation to represent expected volume range which reflects its impact across different markets properly.

7.2.2 Market Modelling

Conduct multi-level market modelling to understand value of Headroom to NGED for connected DERs:

- Split the GB market model into two parts: one that considers the capacity related to NGED distribution networks and another that excludes it. Run model separately to understand the impact and test the potential impact which could flow towards national level.
- Refine the curtailment representation with better technology-specific and seasonal curtailment patterns, e.g. solar PV may have higher curtailment rates in summer than in winter, while wind may have more variability throughout the year.
- With an improved categorisation of Headroom volume, simulate the system benefit for each particular DER type, and link the benefits and investments more closely.

7.2.3 BM Modelling

Considering the relatively small system cost (against the wholesale energy market) in BM, quantify the potential benefit of ESO's action to include further participation of <1 MW distribution generators. A further assessment then needs to be undertaken to understand the level of curtailment impact.

7.2.4 Balancing Services

Conduct a high-level review of the interaction between ANM and Balancing Services in the following key areas:

- Understand the range of costs of Headroom reduction both with and without ANM-BS coordination and revise to reflect the recent increases in Balancing Services expenditure.
- How the figures relate to the generation mix being considered as part of this project, and how the figures could evolve into the future, including a review of new and revised ESO service technical requirements and eligibility rules to ensure assumptions remain valid.
- Update on progress on ANM-BM coordination to improve understanding of the costs and benefits the BM-related impact of Headroom and their allocation.