REPORT

Whole System Thinking (Phase 2) - Curtailment Modelling

Prepared for: National Grid Electricity Distribution

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Executive Summary

Background to the Project

Amidst a backdrop of increasing prevalence of Distributed Generation and growing curtailed renewable generation, National Grid Electricity Distribution have commissioned EA Technology and Baringa to investigate the likely value of increased distribution network capacity on the whole energy system. The concept of the project is to understand whether there is financial value from a whole systems perspective of increasing distribution network capacity to reduce curtailment. For example, does reduced curtailment increase the availability of cheap renewable generation, offsetting costly gas peaker plant generation that would otherwise be required. This project phase aims to understand this question at a high level, for the GB distribution network. This report presents the network analysis methodology used by EA Technology to understand the likely level of curtailment required, assumptions used in that methodology, and a high-level summary of the results.

Scope and Objectives

During Phase 2 of the Whole System Thinking project, EA Technology developed a series of modular improvements to the modelling methodology. A more comprehensive analysis was performed to generate a more accurate representation of likely curtailment across the LV, HV, EHV and 132 kV networks utilising EA Technology's Transform model and NGED's Simple Curtailment Tool. The methodology in stage two included the following components:

- Improving the representation of generation within the seasons.
- Accounting the demand driven network capacity growth.
- Better representation of battery energy storage systems within the network modelling to align with their expected operating behaviour.
- Consideration of abnormal running arrangements.
- Inclusion of emerging V2G technologies.

Key Project Learning

- By 2034, the total annual curtailment across included technologies on the distribution network is calculated at 8.5 TWh, enough electricity to power just over 3.16 million (11%) UK homes for a whole year.
- Curtailment is more prevalent on the 132 kV networks in 2023, and 2028 but by 2034 the LV network dominates for curtailment volumes with the network hitting voltage headroom constraints due to large volumes of connected solar generation.
- The EHV and 132 kV network experiences higher volumes of predicted curtailment outside of the summer months than other voltage levels due to a more varied generation mix with greater volumes of wind and gas generation.
- The relationship between assumed load on the network and associated demand reinforcement is impacted greatly by changing BESS load.

- Using a parametric model gives only an average network wide view of increased curtailment due to outage conditions. Individual networks with connected generators are likely to see much larger curtailment volumes at a local level.
- Predicting forecast curtailment is inherently challenging due to various factors such as governmental policy, supply chain availability and technology costs, consumer behaviour, and other considerations that affect the volumes of connected generation on the network. These in turn influence predicted curtailment volumes. The results presented in this report are based on the assumptions used within the modelling, specifically the application of FES23 System Transformation. Variations would occur if an alternative DER uptake scenario were applied. .

Conclusions.

C2. By 2034, the forecast solar curtailment across the LV-132kV voltage levels is 4.8 TWh this equates to 1.8% of the UK's total current electricity need and 1.2% of predicted electricity demand in 2034.

C3. Based on the methodology assumptions, the total calculated volume of curtailed generation on the distribution network in 2034 is 8.5 TWh, enough electricity to power 3.2 million homes for a year in the UK.

C4. Solar is expected to be the primary driver of curtailment on the distribution network with all technologies seeing an increase in curtailment volumes during daytime hours as a result. This is largely a reflection of the high forecast for installed solar capacity. At a domestic level (LV) this curtailment will be experienced as voltage rise constraints preventing domestic solar from generating freely.

C5. The new governmental policy lifting restrictions on onshore wind development may result in larger volumes of wind curtailment than forecasted in this study due to increased volumes of onshore wind generation connecting to the network.

C6. By 2034 as volumes of domestic solar increase, curtailment on the LV network surpasses that of the higher voltage levels.

C7. The EHV network experiences larger volumes of curtailment outside of the summer that LV or HV networks due to the greater mix of installed generation on the network, particularly LCTs such as wind generation and battery storage.

C8. The 132 kV network experiences higher volumes of predicted curtailment outside of the summer months than other voltage levels due to a more varied generation mix with greater volumes of wind and gas generation.

C9. Changing assumptions around BESS load reduced the volume of curtailment calculated on the EHV voltage level within the three study years.

C10. The HV network experiences a varied impact on curtailment, decreasing in 2023 and 2028, but increasing in 2034; this is likely a result of delayed demand reinforcement with less battery demand load from BESS in the new load profile model.

C11. The minimal proportion of installed BESS on the LV network results in negligible change to curtailment through varying the load profile.

C12. The relationship between assumed load on the network and associated demand reinforcement is impacted greatly by changing BESS load.

C13. Using a parametric model gives only an average network wide view of increased curtailment due to outage conditions. Individual networks with connected generators are likely to see much larger curtailment volumes at a local level.

Recommendations

R1. While the parametric assessment of curtailment can provide a single 'best-view' based on a series of assumptions, it fails to account for the locationality of constraints, which enables the evaluation of areas anticipated to experience higher volumes of curtailment. To effectively analyse the specific locations where preventing curtailment is most valuable to the networks, it is necessary to develop a connectivity-based tool that predicts expected curtailment due to increased volumes of distributed generation.

R2. To enable the potential consumer cost benefits of changing onshore wind policies and increased wind generation, networks must consider how connection queue lengths may delay the availability of potential onshore wind capacity.

R3. Consideration into the impact of changing tap positions to increase voltage headroom and reduce curtailment on KV networks should be considered. This must be balanced however with the potential increase in voltage drop issues and the associated network reinforcement requirements.

R4. To better represent the extremes of the network, that may have large volumes of localised generation and thus experience greater volumes of HV and EHV curtailment a connectivity-based model specifically developed for forecasting network curtailment is needed.

R5. Development of a load flow curtailment estimator will allow for calculation of more accurate curtailment values for generators increasing customer satisfaction and enable more LCT generation connections.

R6. When reviewing the impact of battery energy storage on consumers and the network, the response of batteries to both economic signals (high whole price for electricity) and network signals (curtailment due to network overload) must be considered.

R7. A combined network and economic model to anticipate the behaviour of BESS on the network and the potential benefits or costs to consumers is needed to help direct policy behind battery storage behaviour at the grid scale.

R8. To gain a more realistic evaluation of the local impact of planned outages on networks with connected generation a local connectivity-based assessment should be performed.

Contents

Figures List

Tables List

1. Background and Introduction

EA Technology, together with project partners Baringa, were asked to assess whether investment in the distribution network could be justified on the basis on whole system benefits to the electricity system. One hypothesis explored in this project is whether distribution network investment to increase capacity could be justified through the resulting reduction in renewable energy curtailment, facilitating more clean and cheap electricity onto the grid in place of costly gas peaker generation.

The project is split into two stages. Stage 1 of this project was completed in March 2024 and acted as an initial assessment into the potential benefits of distribution network investment to reduce generation curtailment on the GB electricity markets[1]. Stage 2 of this project, discussed in this report, takes the learnings and outcome of Stage 1 to produce a 'Best View' analysis of the volumes of GB network curtailment.

Stage 2 addressed the following changes in the curtailment modelling methodology:

1. Development of improved seasonal generation load profiles.
2. Addition of Vehicle-to-Grid electric vehicle charging technology.
3. Network demand reinforcement.
4. Differing battery storage profiles assumptions.
5. Abnormal network running conditions.
6. A complete LV-132 kV view of curtailment.

This report presents the updated methodology EA Technology have adopted in Stage 2 of the Whole System Thinking project to produce a 'Best View' model of curtailment from LV – 132 kV voltage levels, detailing assumptions used throughout the modelling and their effect on the overall view of curtailment. Curtailment volumes for four generation types: solar, wind, gas and battery storage have been assessed at each voltage level for the years 2023, 2028 and 2034 and are included within the report.

[1] Stage 1 Report - National Grid - Headroom - Whole System Thinking

2. Definitions

ADMD	After Diversity Maximum Demand
ANM	Active Network Management
BESS	Battery Energy Storage System
BSP	Bulk Supply Point
DFES	Distribution Future Energy Scenarios
DNO	Distribution Network Operator
ECR	Embedded Capacity Register
EHV	Extra High Voltage
EV	Electric Vehicle
EVCP	Electric Vehicle Charge Point
FES	Future Energy Scenarios
GB	Great Britain
GSP	Grid Supply Point
HP	Heat Pump
HV	High Voltage
LCT	Low Carbon Technology
LIFO	Last In First Out
LV	Low Voltage
NGED	National Grid Electricity Distribution
NESO	National Energy System Operator
PV	Photovoltaics
UK	United Kingdom
SCT	Simple Curtailment Tool

3. Phase 2 Methodology Development

Phase 2 of the Whole System Thinking project built on the models developed in Stage 1. To produce a more representative view of network curtailment a series of developments were made to the Transform model, these will be discussed in more detail in this section.

Outside of the areas discussed in this section of the report, no changes were made to the Transform model. As a result, network details and feeder archetypes, low carbon technology uptake rates, technology deployment volumes and clustering assumptions all remain the same as within Stage 1. Details of assumptions around these model factors are included in the Stage 1 report[2].

3.1 Improved Seasonal Profiles

During Stage 1 of the Whole System Thinking project, it became clear that the four Distribution Future Energy Scenarios (DFES) daily load profiles (winter peak demand, summer peak generation, intermediate cool/warm demand) were not sufficient to display generation across an entire year. This resulted in a concentration of generation in June, July and August, outside of these months load profiles were demand based and no generation was present. For Stage 2 of this project, EA Technology have undertaken analysis of the yearly generation profiles for wind and solar generation included within National Grid Electricity Distribution's (NGED) Simple Curtailment Tool (SCT). From this, new solar and wind generation half hourly load profiles were developed from multiple examples of these two technologies yearly loads across the NGED network.

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

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

Where:

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

A data workbook containing the seasonal profiles used for all technologies within Transform was shared with NGED during this project[3].

[2] National Grid - Headroom - Whole System Thinking
[3] Seasonal Profile Data workbook

3.1.1 Seasonal Profiles Development Methodology

The technologies used within the Transform modelling for Stage 2 of this project were unchanged from Stage 1. The FES 2023 scenario "System Transformation" was used for the uptake rates and load profiles were extracted from NGED's DFES 2023. Detailed discussion around the uptake rates and load profiles used to develop the Transform models are included in Section 3 of the Phase 1 report[4].

Demand Load

The peak demand daily load profiles for each technology were taken from DFES for each of the four seasons (summer, winter, intermediate cool and intermediate warm). This load profile was aligned to the peak demand day within the Stage 2 modelling. The property-based load profiles are taken directly from Transform's internal base load calculations and the vehicle-to-grid (V2G) load profile from the Crowd Charge project (V2G methodology is discussed further in Section 3.2).

For Stage 2, an average demand day and a peak generation demand load is also required for each season. The daily load profiles for average day and peak generation day are calculated as follows:

- Average day = 50% peak demand day.
- Peak generation day = 30% peak demand day.

This results in three representative day demand profiles (peak demand, average demand and peak generation) for each season. Figure 1below gives an example of the three different profiles for winter domestic heat pump load.

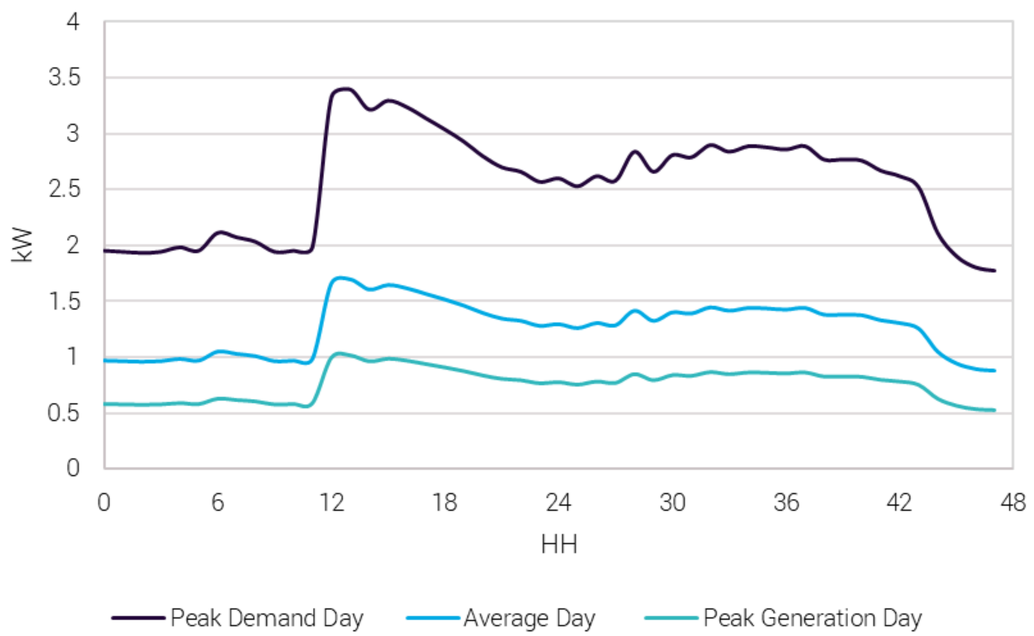


Figure 1: 48 HH demand load profiles for domestic heat pumps on a peak demand, average and peak generation day in the winter season.

[4] National Grid - Headroom - Whole System Thinking Phase 1 Modelling

I&C customer load does not have the same logic applied. I&C loads are assumed to remain constant throughout the year.

Generation Load

The 12 representative day wind and solar generation profiles were developed through analysis of NGED's SCT using the following methodology.

The kW sum of wind and solar generation was calculated at each half hour of an entire year. This gave a resultant total capacity of generation for every half hour of a single year. From the combined solar and wind load, the daily average generation in kW/kW_{peak} can be calculated. Using the combined solar and wind average, the days within a season can be compared relative to one another and assigned as low generation days, high generation days or mid-range generation day. Each day of the combined average generational load per season was analysed to produce the following:

- The day with 20th percentile average combined generation load.
- The day with 50th percentile average combined generational load (median).
- The day with 80th percentile average combined generation load.
- The day with Peak generation average combined generational load.

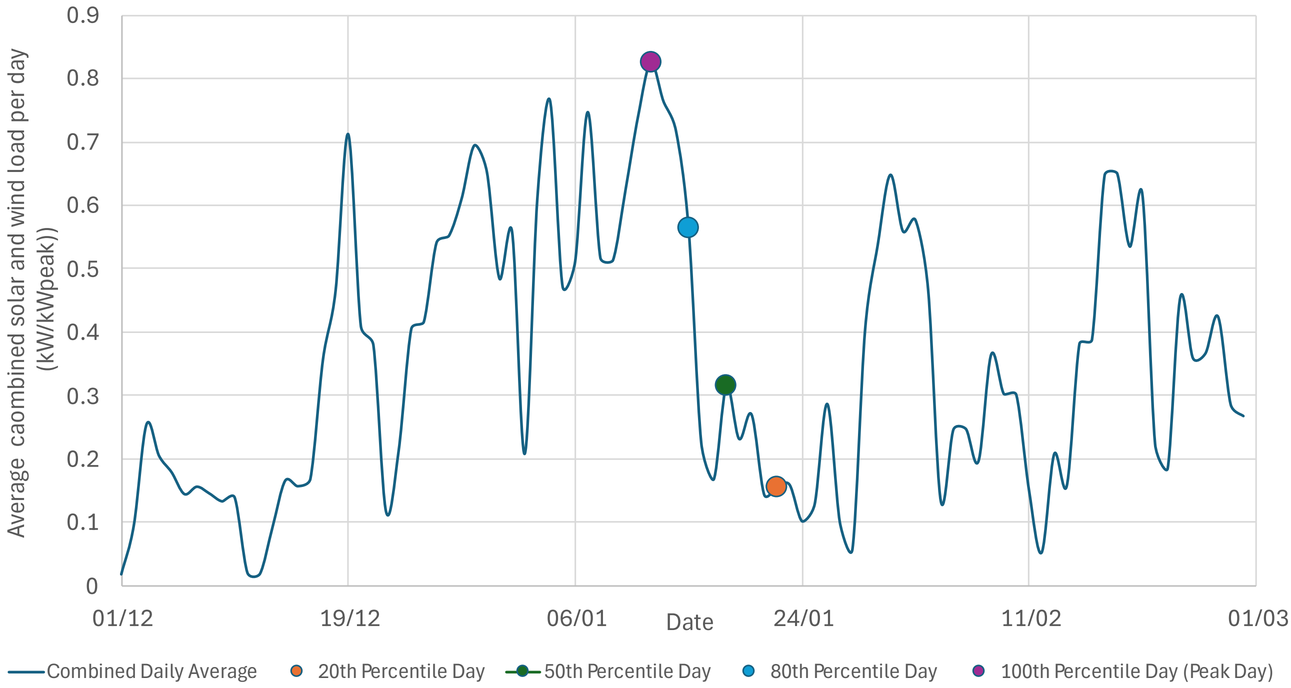


Figure 2: The daily average of the combined load of wind and solar generation for the winter season with the 20th, 50th. 80th and 100th percentile days highlighted.

The 48HH wind and solar daily load profiles for the 20th percentile, 50th percentile and 100th percentile day within the season were then extracted as the 3 representative days, peak demand day, average day and peak generation day respectively, to be used for the analysis.

The generation profiles for the remaining days within a season were produced through scaling the load profile of three representative days as follows:

- 1st – 20th percentile days – scaled relative to 20th percentile day – high demand, low generation days.
- 21st – 79th percentile days – scaled relative to 50th percentile day. – average demand and generation days.
- 81st percentile – peak days – scaled relative to peak (100th percentile) day -low demand, high generation days.

Within each of these ranges, a scaling factor was calculated for each day relative to the combined generation load from the SCT data. For example, if the average daily load is 0.83 kW and 0.58 kW on the peak and 80th percentile days respectively the peak day representative load profiles for solar and wind would be scaled by a factor of 0.7 to produce the 80th percentile day load profiles. Figure 3shows how the peak generation day wind generation load profile during the winter season has been scaled over a selection of top 20th percentile days to illustrate this process.

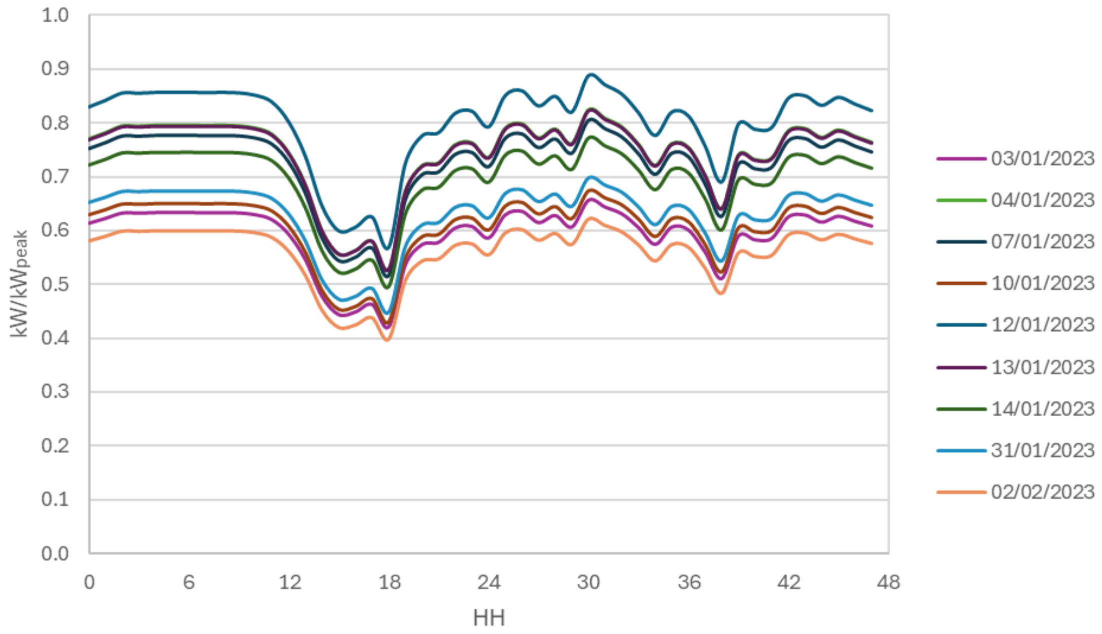


Figure 3: Representative day scaling example. This figure shows the scaling of the representative peak generation day for wind for a selection of days within the winter season between the 80th percentile day and the peak day.

Within a single season all days were scaled following the same methodology highlighted in Figure 3. This results in all days within a season having an individual 48HH load profile for solar and wind generation. This process was repeated for all four seasons to produce a 48HH solar and wind load profiles for all 365 days of a single year.

The solar and wind generation within each season produced from the scaling of three days was then compared to the actual 365 day load from the SCT in order to statistically compare the representativeness of our chosen days[5]. The statistical analysis showed very little difference in the total load experienced within a single season (Table 1).

[5] EA24155 - D1-D02 – Seasonal Load Profiles Statistical Analysis

Table 1: Statistical analysis comparing the total season load from the SCT and the total load within a season produced from scaling three representative days (total load is calculated from the area under the load profile).

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

Whilst the total load within a season is extremely similar when comparing the SCT generation profiles and the scaled year. It should be noted that use of three days scaled to represent a single season does lead to cases of over or under estimation of load compared to the SCT and is one of the limitations of using representative days to represent an entire year.

For example, a day within the average representative day range could have a larger proportion of wind and much less solar then the 50th percentile day. However, this day will be generated as a scaling of 50th percentile day load potentially overestimating the solar contribution and underestimating the wind or vice versa. Figure 4 below shows how this can lead to mismatches in the load shape over a season when comparing the SCT 365-day load to the profiles produced through scaling.

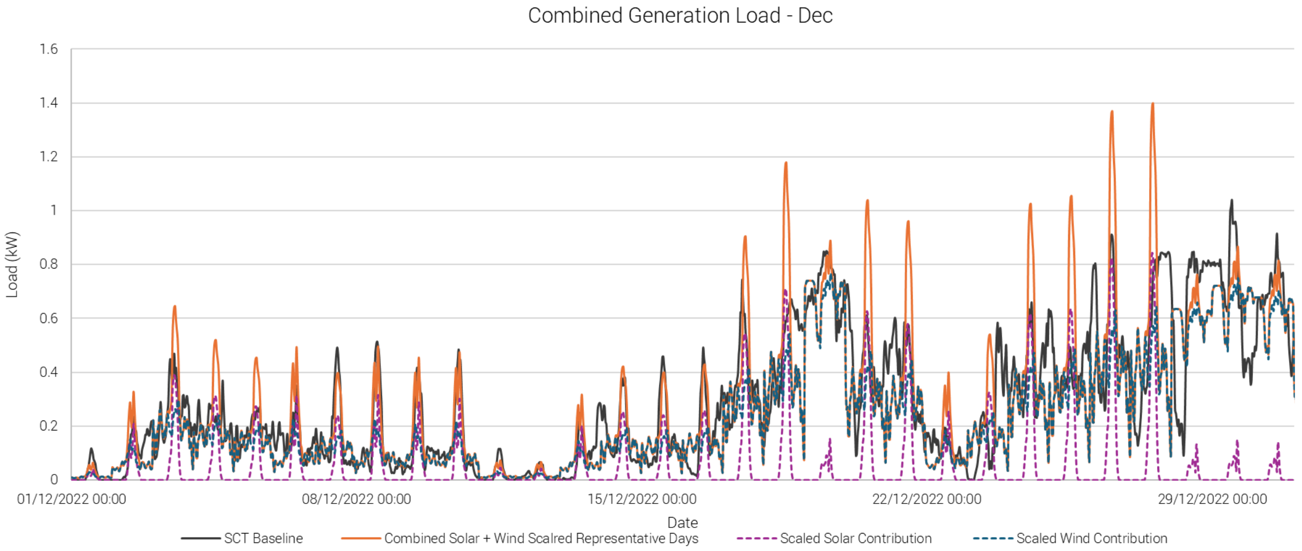


Figure 4: Comparison of the SCT load profile, with the load profile of the scaled representative days for the month of December. This highlights how the contribution of solar may be overestimated on days with more wind contribution leading to peaks during the day that may not be present in the SCT solar profiles.

Other generation load (gas peakers) has not been analysed to produce new seasonal generation profiles using the SCT (as the SCT assumption is an always on or off-load for the 'other' category which includes gas generation). This profile was developed through Phase 1 of the project using load data from Baringa's PLEXOS modelling. For this technology the same logic as demand has been applied with 50% load on average day and 30% load for a peak demand day.

Impact on overall curtailment results

Assumption	Effect on analysis	Impact on curtailment	Mitigation
Twelve representative days are scaled to make the load profiles for 365 days.	The load profile for all days will follow the same twelve patterns. However, in practice, weather patterns are rarely consistent and can be challenging to predict. This may result in overestimations of load on some days if the actual solar contribution is low when total load is high, and underestimations on other days if wind contributions outside of daytime hours are not fully accounted for in the representative load profile.	Neutral Total load will balance to reflect the whole season, however there may be instances of shape difference in the load e.g., load peaks during the day for solar (where the actual load factor was mainly wind) that leads to curtailment in our analysis that wouldn't be occurring in the real system.	EA Technology tried multiple combinations of load profiles using varying percentile days until the best statistical fit to the data occurred.

3.1.2 Representative Day Profiles

Winter

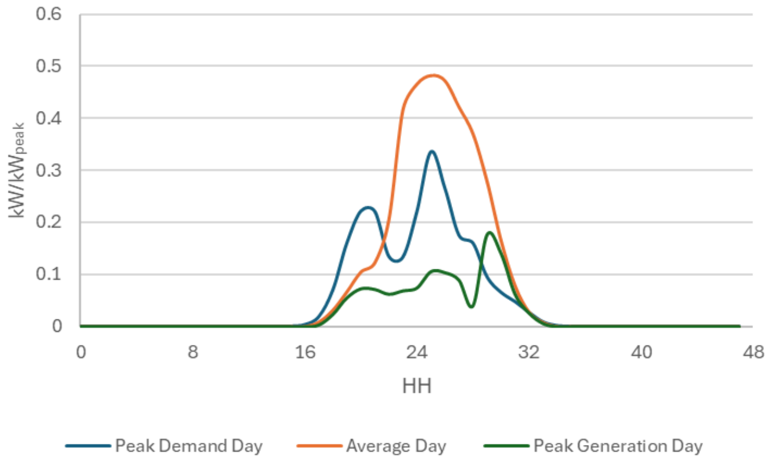


Figure 5: Solar generation daily load profile for winter season representative days.

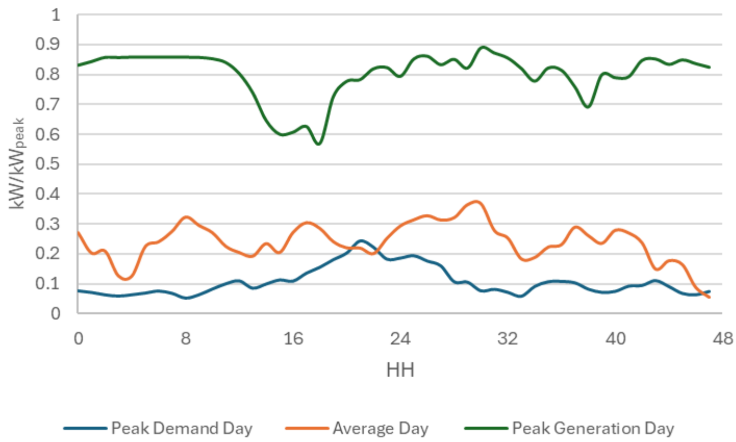


Figure 6: Wind generation daily load profile for winter season representative days.

The representative winter days extracted in the analysis have the following characteristic:

- Peak generation day – high wind, mid-low solar
- Average day – low wind, mid solar
- Peak demand day – low wind, low solar.

Summer

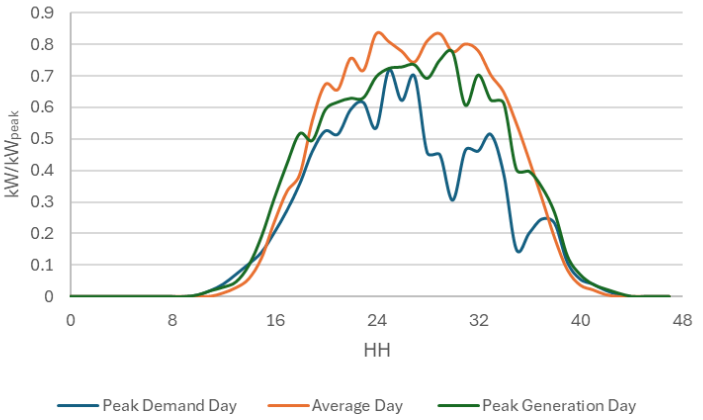


Figure 7: Solar generation daily load profile for summer season representative days.

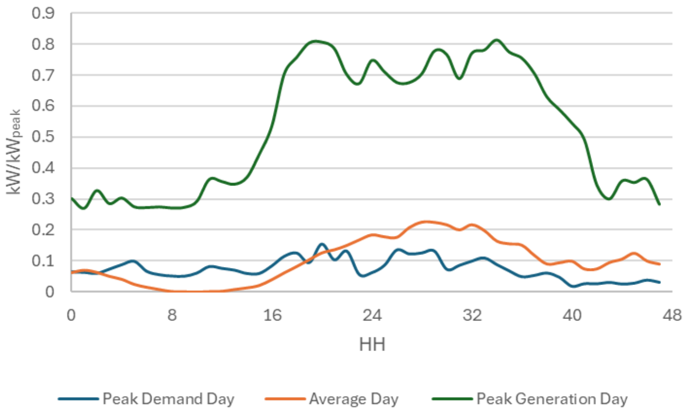


Figure 8: Wind generation daily load profile for summer season representative days.

The representative summer days extracted in the analysis have the following characteristic:

- Peak generation day – high wind, high solar.
- Average day – low wind, high solar.
- Peak demand day – low wind, mid solar.

Intermediate Cool

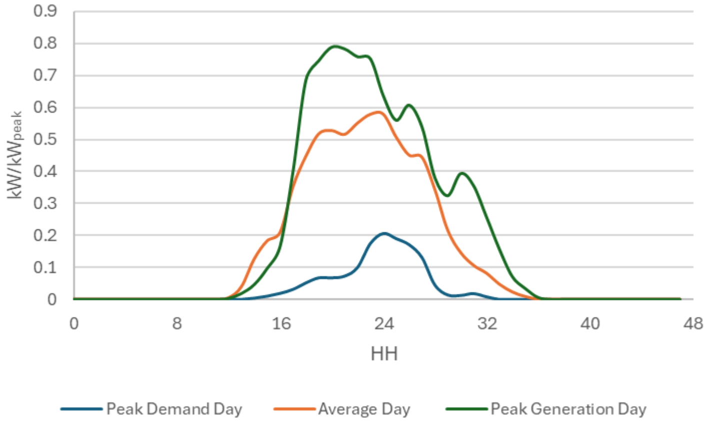


Figure 9: Solar generation daily load profile for IC season representative days.

Figure 10: Wind generation daily load profile for IC season representative days.

The representative intermediate cools days extracted in the analysis have the following characteristic:

- Peak generation day – high wind, high solar
- Average day – mid wind, mid solar
- Peak demand day – mid wind, low solar.

Intermediate Warm

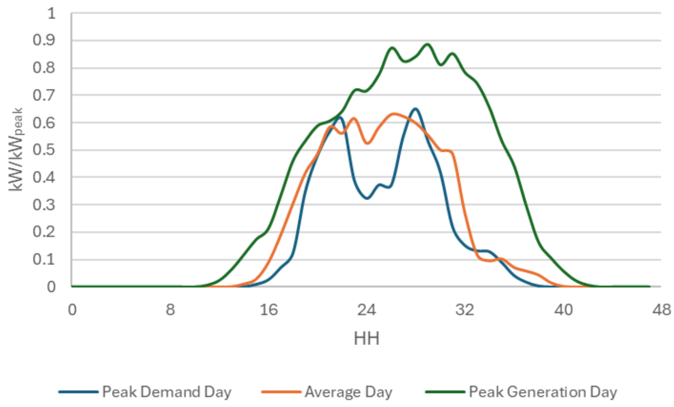


Figure 11: Solar generation daily load profile for IW season representative days.

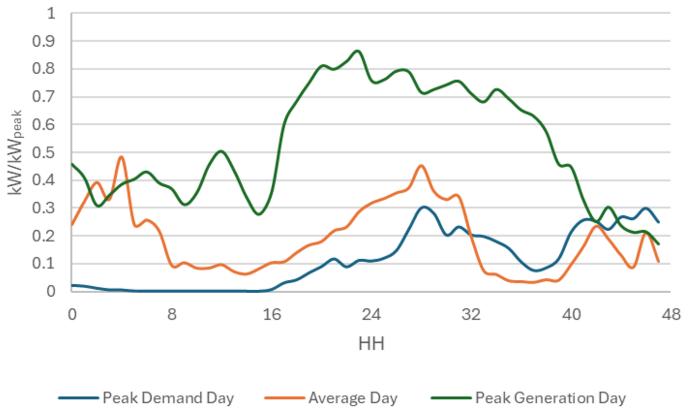


Figure 12: Wind generation daily load profile for IW season representative days.

The representative intermediate warm days extracted in the analysis have the following characteristic:

- Peak generation day – high-mid wind, high solar
- Average day – mid wind, high-mid solar
- Peak demand day – low wind, mid-low solar.

3.1.3 Alignment to PLEXOS Power Market Model

During Stage 2 of the project the number of representative days used in the Transform modelling increased from four to twelve. As described in Section 3.1.2, the three representative days within a season were scaled to produce a whole year (365-days) of load profiles. Similarly, to the methodology used in Stage 1, the 365-days of profiles produced through scaling were aligned to Baringa's 2017 weather year[6].

Baringa's 2017 demand load data was assessed for each season and the 20th, 50th and 100th percentile days were found. Each associated representative day was assigned to its equivalent day in Baringa's weather year data, i.e., the day with highest demand is matched to the peak demand representative day. The same approach was then taken to align the days scaled relative to representative days to their equivalent day in Baringa's weather year ensuring a similar demand profile during the year.

Table 2: Alignment of load within the SCT generational profiles, with Baringa's 2017 weather year demand profiles used with the PLEXOS power market modelling.

Baringa 2017 year date	Load Rank[7]	Baringa Demand Assignment	Transform Profile Day	SCT Rank Aligned Date	Applied Representative Day Scaling Factor
01/01	5	Low Demand	Winter Peak Generation Day	*11/01*	0.90
02/01	14	Low Demand	Winter Peak Generation Day	*20/02*	0.75
03/01	54	Average	Winter Average Day	*05/02*	0.78
04/01	61	Average	Winter Average Day	*04/12*	0.65
05/01	83	High Demand	Winter Peak Demand Day	*27/01*	0.65
06/01	71	Average	Winter Average Day	*07/12*	0.50
07/01	20	Average	Winter Average Day	*01/01*	1.77
08/01	12	Low Demand	Winter Peak Generation Day	*17/02*	0.79
09/01	48	Average	Winter Average Day	*26/01*	0.91
10/01	57	Average	Winter Average Day	*21/02*	0.71
11/01	50	Average	Winter Average Day	*20/01*	0.86
12/01	75	High Demand	Winter Peak Demand Day	*06/12*	0.93
13/01	76	High Demand	Winter Peak Demand Day	*21/01*	0.93
14/01	32	Average	Winter Average Day	*23/02*	1.44
15/01	21	Average	Winter Average Day	*27/12*	1.75

[6] 2017 is the weather year used within Baringa's PLEXOS power market modelling. In order to best ensure alignment of the two load profiles within the two methodologies we scaled our representative days to this data set.
[7] Load is ranked from lowest demand in the winter season (Dec-Feb) as 1 and highest demand as 90.

3.2 Vehicle-to-Grid

For Stage 2 of the Whole System Thinking project, vehicle to grid (V2G) charging of electric vehicles (EVs) is to be included as a technology within the modelling so the value of LV network headroom can be assessed. To do this successfully, a 48HH load profile and uptake rates for this technology are needed for the Transform model.

The 48HH V2G profile utilised within Transform is taken directly from data collected as part of the Crowd Charge project[8] completed for NGED (formally Western Power Distribution). The Crowd Charge project was undertaken as part of the Electric Nation Smart Charging Trial exploring the impact of V2G charging on the LV network through an end-user trial, to produce real-life charging data for analysis. The V2G profiles were then subsequently developed as part of the Electric Nation V2G project[9].

EA Technology utilised Monte Carlo analysis of the generated charging profiles to produce a realistic demand profile for a vehicle performing V2G charging. Analysis was carried out for 23 vehicle chargers. The values were then scaled down to an individual charger to create ACE49 style profiles, that incorporated a mean and variable component.

3.2.1 V2G 48HH load profile

A 48HH ADMD load profile for V2G charging for this project has been produced based on data analysed from the Crowd Charge project.

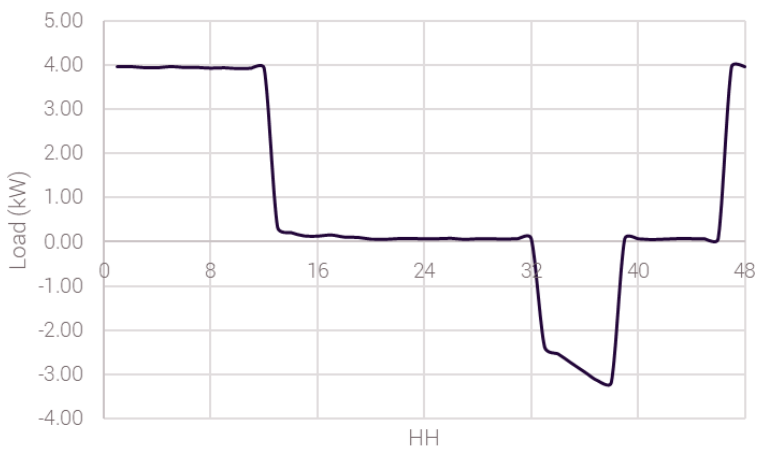


Figure 13: 48HH Vehicle-to-Grid load profile

8 CrowdCharge gains key insights into smart charging - CrowdCharge, National Grid - Electric Nation - Powered Up
9 Project EA10618 CrowdCharge Electric Nation V2G Profiles

3.2.2 V2G uptake rates

Uptake rates for V2G charging have been calculated from the System Transformation Scenario within the FES 2023 data workbook[10] as unabated charging (customer charging is not managed and can occur freely), flexed (customers are on time-of-use charging tariffs and therefore charge outside of peak times), and V2G (the portion of flexible customers that participate in V2G charging). The uptake rates are given in Table 3 below.

Table 3: Vehicle-to-Grid uptake rates based on FES 2023 data.

Year	Unabated Charging	Flexed Charging	FES2023 V2G%	V2G Charging Numbers
2023	26,628.10	93,029.70	0.0%	
2024	36,766.70	120,320.50	0.0%	
2025	49,527.80	155,519.40	0.0%	
2026	65,981.90	201,635.50	0.0%	
2027	87,196.90	259,687.40	0.0%	
2028	114,296.70	332,606.70	0.1%	332.6
2029	148,178.50	422,415.00	0.1%	422.4
2030	190,358.10	530,969.80	0.2%	1,061.9
2031	255,603.00	652,682.80	0.2%	1,305.4
2032	337,608.60	792,516.10	0.3%	2,377.5
2033	438,970.70	947,612.40	0.5%	4,738.1
2034	557,814.90	1,112,614.50	0.6%	6,675.7
2035	692,063.20	1,273,513.50	0.8%	10,188.1
2036	827,079.80	1,433,525.10	1.1%	15,768.8
2037	955,395.70	1,581,935.40	1.4%	22,147.1
2038	1,064,927.60	1,710,933.70	1.8%	30,796.8
2039	1,147,638.80	1,821,192.20	2.3%	41,887.4
2040	1,203,678.60	1,914,820.40	3.0%	57,444.6
2041	1,220,768.60	2,007,231.30	3.7%	74,267.6
2042	1,219,490.50	2,078,713.50	4.6%	95,620.8
2043	1,191,889.20	2,112,969.70	5.6%	118,326.3
2044	1,181,900.70	2,094,300.60	6.7%	140,318.1
2045	1,168,922.10	2,070,648.80	7.7%	159,440.0
2046	1,152,582.20	2,040,906.80	8.7%	177,558.9
2047	1,133,266.20	2,005,886.60	9.7%	194,571.0
2048	1,116,004.30	1,973,783.30	10.5%	207,247.2
2049	1,098,462.00	1,941,054.40	11.2%	217,398.1
2050	1,079,974.80	1,906,577.70	11.8%	224,976.2

[10] FES Documents | ESO (nationalgrideso.com) – FES 2023 Data Workbook

3.3 Demand Reinforcement

During Stage 1 of the Whole System Thinking project, the asset ratings within the curtailment analysis were fixed to baseline 2023 ratings for all study years (2023, 2028 and 2034) for the purpose of enabling the initial analysis. It was understood that this assumption, whilst an adequate approach for the initial project stage, was not a sufficiently accurate reflection of the reinforcement process within the distribution networks; for later stages of the project.

Standards with which the GB distribution networks must comply require that at lower voltage levels (particularly LV) the network must have sufficient capacity to meet demand requirements of the users[11]. Therefore, the network operators' must ensure that the network is sufficiently reinforced to meet growing demand.

For Stage 2 of the project a new processing logic was developed to analyse the transform results and ensure assets within the models are upgraded over the study window by accounting for increasing demand-load related network reinforcement. The reinforcement for the different voltage levels is:

- LV – assets are reinforced when a demand constraint is breached but not for generational constraints.
- HV – as LV.
- EHV – assets are reinforced based on NGED's business plan for network reinforcement.

3.3.1 LV and HV reinforcement methodology

Through discussion with NGED it was determined that the LV and HV networks will be treated the same in the Phase 2 modelling. For these networks, the asset ratings within the network modelling will increase based on the application of a Transform based solution to solve any demand triggered constraints witnessed by the network. If a constraint is experienced that is due to generation only, reinforcement does not occur and the network asset ratings remain unchanged.

The reinforcement logic is explained in Figure 14.

The type of constraint, whether demand or generation, is determined solely by the nature of the constraint occurring at the initial point of asset overload. I.e., if a generation constraint is seen in 2025 followed by a demand constraint in 2028 (within the 10-year look ahead period), the constraint will be considered a generational constraint until 2028. For the avoidance of doubt, there will be no increase in asset ratings until 2028.

If a demand and generation constraint occur in the same year, the logic will treat this as a demand constraint and reinforcement will be applied.

[11] Energy Act 2013: Part 2, Chapter 3, Section 27

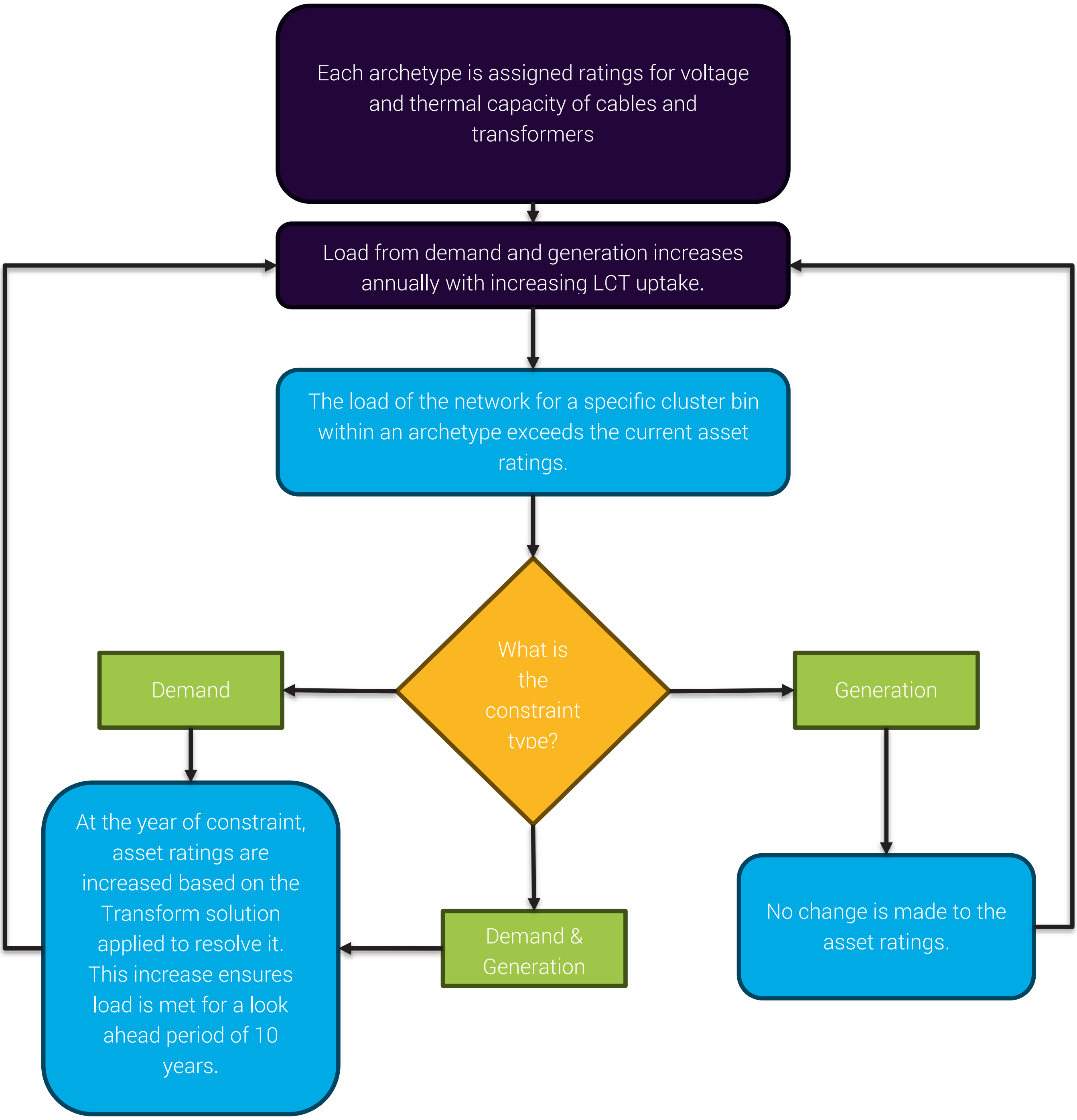


Figure 14: LV and HV demand reinforcement logic flow chart.

3.3.2 EHV reinforcement methodology

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

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

This analysis also found the following spread of trigger times and archetype assignments:

Table 4: Number of reinforcement upgrades by year

Trigger Year	Number of Reinforcement Upgrades	Cumulative % Reinforcement Upgrades
2025	9	32%
2026	5	50%
2027	6	71%
2028	3	82%
2029	1	86%
2030	1	89%
2031	2	96%
2032	0	96%
2033	1	100%

Table 5: Number of Reinforcement Upgrades by Network Archetype

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

It is evident from the analysis that the majority (82%) of the reinforcement work is occurring prior to 2028 and within the very early stages of our study period. Alongside this, 50% of the reinforcement work is due to be on rural BSPs (names and archetype assignment of substations taken from the planned reinforcement data analysis are given in Appendix I).

Analysis of NGED's network data gives 256 total BSPs within all 4 of NGEDs licence areas. Based on previous analysis of the distribution substations throughout this project to assign NGED substations to network archetypes (Stage 1 report, Section 3.4.2), the archetype split of these 256 BSPs is: c41% rural, c25% suburban, and c35% urban (a similar ratio to the split of BSPs being reinforced). The reinforcement requirements for each archetype are therefore calculated as below (Table 6):

Table 6: EHV reinforcement requirements as a portion of archetype.

Archetype	Total Number of Networks	Network Requiring Reinforcement	% Network upgraded
Rural	104	14	15.9%
Suburban	64	6	9.4%
Urban	88	8	7.7%

The proportion of the 256 NGED BSPs per archetype expecting reinforcement per year can be then calculated. The total numbers are displayed in Table 7.

Table 7: Number of networks requiring reinforcement per year.

Year	Total Reinforcements	Rural	Suburban	Urban	Rural %	Suburban %	Urban %
2025	9	7	1	1	8.0%	1.6%	1.0%
2026	5	0	2	3	0.0%	3.1%	2.9%
2027	6	2	3	1	2.3%	4.7%	1.0%
2028	3	3	0	0	3.4%	0.0%	0.0%
2029	1	0	0	1	0.0%	0.0%	1.0%
2030	1	0	0	1	0.0%	0.0%	1.0%
2031	2	1	0	1	1.1%	0.0%	1.0%
2032	0	0	0	0	0.0%	0.0%	0.0%
2033	1	1	0	0	1.1%	0.0%	0.0%

The percentage of rural, suburban or urban networks that are expected to be reinforced based on NGEDs business plan can then be scaled to the number of networks within each Transform archetype that would require reinforcement per year (Table 8).

Table 8: Transform networks requiring reinforcement.

	EHV1	EHV2	EHV3	EHV4	EHV5	EHV6
Total Networks	540	810	360	840	257	200
2025	5.19	7.79	5.63	13.13	20.45	15.91
2026	15.58	23.37	11.25	26.25	0.00	0.00
2027	5.19	7.79	16.88	39.38	5.84	4.55
2028	0.00	0.00	0.00	0.00	8.77	6.82
2029	5.19	7.79	0.00	0.00	0.00	0.00
2030	5.19	7.79	0.00	0.00	0.00	0.00
2031	5.19	7.79	0.00	0.00	2.92	2.27
2032	0.00	0.00	0.00	0.00	0.00	0.00
2033	0.00	0.00	0.00	0.00	2.92	2.27

Within Transform the load at each archetype is distributed within cluster bins, where cluster bin 0 has a larger proportion of load distributed to a smaller number of networks. The distribution of load within each bin then decreases relative to the number of networks, where cluster bin 9 has a smaller proportion of load distributed over a larger volume of networks. This means that assets within cluster bin 0 will exceed their voltage and thermal ratings at an earlier year and therefore require load reinforcement sooner than those in cluster bin 9. It is through this method that Transform adds a level of variation between networks with high uptake rates of LCTs and those with lower uptakes, representative of areas of high and low technology uptake expected in reality.

The number of networks within each cluster bin for the six EHV archetypes are shown in Table 9.

Table 9: Number of EHV networks per cluster bin in each archetype within Transform.

Cluster Bin	0	1	2	3	4	5	6	7	8	9	
Proportion of total Networks within Cluster Bin (%)	0.5	0.5	1.5	2.5	12.5	12.5	15.0	15.0	20.0	20.0	*Total Networks*
EHV1 Urban Underground Radial	2.7	2.7	8.1	13.5	67.5	67.5	81	81	108	108	*540*
EHV2 Urban Underground Meshed	4.1	4.1	12.2	20.3	101.3	101.3	121.5	121.5	162	162	*810*
EHV3 Suburban Mixed Radial	1.8	1.8	5.4	9.0	45	45	54	54	72	72	*360*
EHV4 Suburban Mixed Meshed	4.2	4.2	12.6	21	105	105	126	126	168	168	*840*
EHV5 Rural Overhead Radial	1.3	1.3	3.9	6.4	32.1	32.1	38.6	38.6	51.4	51.4	*257*
EHV6 Rural Mixed Radial	1.0	1.0	3.0	5.0	25	25	30	30	40	40	*200*

The two data sets within Table 8: Transform networks requiring reinforcement. and Table 9 can then be combined to determine the annual reinforcement within each cluster bin based on the number of networks requiring reinforcement. A worked example with EHV6 archetype is shown below:

In 2025, c8% of rural networks require reinforcement, equating to 15.91 of the 200 EHV6 networks within Transform. Based on the total number of EHV6 networks per cluster bin and the numbers requiring reinforcement in 2025, cluster bins 0, 1, 2 and 3 all require all networks to be fully reinforced and cluster bin 4 requires partial upgrades (see Table 10). Currently within Transform a major works gives a network reinforcement of 500% which has been assumed here.

Table 10: EHV6 worked example of cluster bin reinforcement volumes.

Cluster Bin	0	1	2	3	4	5	6	7	8	9	*Total*
Total EHV6 networks per cluster bin	1.0	1.0	3.0	5.0	25.0	25.0	30.0	30.0	40.0	40.0	*200*
Number of EHV6 networks reinforced in 2025	1	1	3	5	5.91	0	0	0	0	0	*15.91*
Network rating increase in 2025	500%	500%	500%	500%	118%	0%	0%	0%	0%	0%	

The thermal cable asset ratings within our analysis in 2025 would therefore increase as follows where by cluster bin 4 all 15.91 networks have been reinforced so only partial reinforcement (118%) occurs:

Table 11: Thermal cable asset ratings per cluster bin in 2025 based on reinforcement.

Cluster Bin	0	1	2	3	4	5-9
Rating Type	Thermal Cable (kW)	Thermal Cable (kW)	Thermal Cable (kW)	Thermal Cable (kW)	Thermal Cable (kW)	Thermal Cable (kW)
Start	16140	16140	16140	16140	16140	16140
2025	80700	80700	80700	80700	19074.55	16140

Impact on overall curtailment results

Assumption	Effect on analysis	Impact on curtailment
LV and HV voltage levels are upgraded at the point of a demand constraint	Transform analysis determines the best intervention for constraints occurring at LV and HV.	Neutral at LV Underestimation at HV Areas of HV network reinforcement will likely be assessed in a manner similar to EHV. This means reinforcement could potentially be implemented earlier in our modelling than in reality, thereby reducing curtailment volumes.
EHV voltage levels are reinforced based on the business plan	More heavily loaded cluster bins are upgraded first, i.e., cluster bins 0-3. These cluster bins also contain greater volumes of generation as well as demand load. In practice, BSPs with significant generational load may not encounter substantial demand volumes, leading to limited reinforcement and higher instances of curtailment.	Underestimation The highly generation loaded cluster bins are also the most demand loaded which isn't necessarily reflective of locations within reality. This could lead to an underestimation of curtailment volumes due to reinforcement occurring in our model where it wouldn't on high generation BSPs in the network that have lower demand.

3.4 Abnormal Running Conditions

For Stage 2 of the Whole System Thinking project, periods of time where the network is running in abnormal running conditions are being considered for the impact upon curtailment. Abnormal running conditions were assessed for their impact within the Transform analysis only, assessment of the 132 kV voltage level was not possible due to the SCT not having the capability for this assessment. Transform already considers the network to be running with N-1 redundancy i.e., the network is resilient against a 1st outage based on the P2 Engineering recommendations. However, it is known that there are periods of time within which the network is already in N-1 conditions due to planned outages. Should a second, unplanned outage occurs during this time frame (N-1-1) the effect on curtailment of distributed generation must be considered.

For this stage of the project, EA Technology have assessed outage data from NGEDs region to determine what a typical year of planned outages looks like. During these times, should a secondary outage occur (N-1-1 conditions) distributed generation on these networks will experience increased curtailment volumes not currently assessed through Transforms N-1 asset ratings.

3.4.1 Outage Data Analysis

Historic outage data from NGED's region from 2000 – 2024 was supplied by NGED. Substations within the data were mapped to Transform archetypes based on pervious analysis work during Phase 1 of the Whole System Thinking project to link Transform Archetypes to NGED substations.

The 24 years of outage data was analysed to determine what a typical year of planned outages looked like. To prevent the arbitrary placing of outage days based on average planned outage duration, EA Technology believes using a single year of outage data is the best option. From our analysis we have determined 2021 to be representative of a typical year of planned outages. Below is the methodology to explain how this was determined.

First, within the data supplied by NGED there is no HV outage data within the assessment until 2016, so these years were discounted. There was also an anomalously high count of planned outages in 2016 on the HV rural networks, so this was also removed from the data set. As 2024 has not completed a full year yet this (and the years later than 2024) was also removed.

Table 12: Analysis of the planned outage data for all supplied years[12].

	1999	2000	2001	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2118
EHV Rural																									
EHV Suburban																									
EHV Urban																									
HV Rural																									
HV Suburban																									
HV Urban																									

[12] Numerical data has been removed from the data tables due to confidentiality. The colour scaled used shows low numbers of planned outages in green tending through yellow to high numbers of planned outages in red.

The years 2017 – 2023 were then analysed further to extract analysis of the sum, count and average duration of planned outages per month each year.

Table 13: Sum of duration of planned outages for every month from 2017 - 2023.

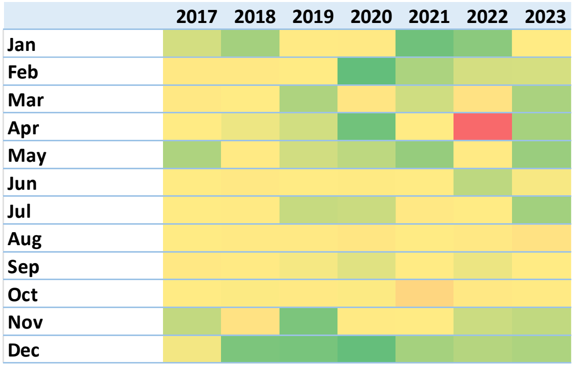


Table 14: Average durations of planned outages for every month from 2017 - 2023.

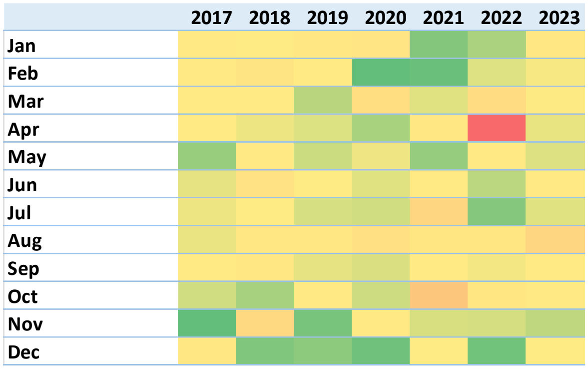
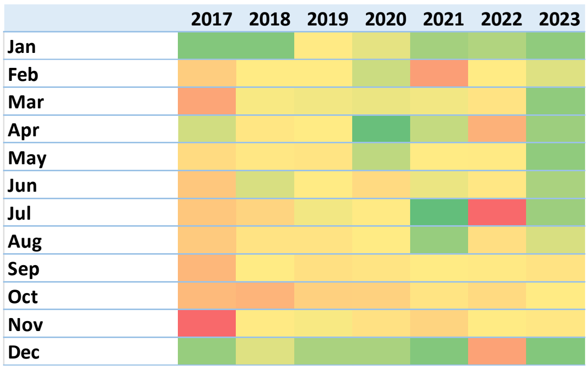


Table 15: Count of planned outages in every month from 2017 - 2023.



Between 2017 and 2023 the average of the total sum, average and count of planned outages were calculated as follows:

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

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

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

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

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

Impact on overall curtailment results

Assumption	Effect on analysis	Impact on curtailment
Planned outages are assessed to an archetype level only.	The effect of derating due to planned outages is spread over all networks within an archetype. This dilutes the isolated impact a single network would experience in planned outages conditions. Using a parametric model removes the granular impact of specific network locations.	**Underestimation** Generators on individual networks would experience a larger impact on curtailment should a planned outage occur at an individual network. These generators could be curtailed fully for the duration of the works at a single substation.

3.4.2 Curtailment analysis

To produce a best view of curtailment on the network, a combination of curtailment volumes for normal and abnormal running conditions must be considered. A Transform model was produced to calculate the volume of curtailment in 2023, 2028 and 2034 on a network model with all assets rated based on abnormal running conditions. As previously stated, the SCT did not assess abnormal running conditions on the 132 kV voltage levels, so this analysis was performed only on the Transform assessed voltage levels (LV-EHV).

From the analysis of planned outages during 2021 on NGEDs network, the number, date, and duration of networks undergoing planned outages was extracted to an archetype level. Archetypes were assigned to the NGED substations from LV-EHV during Phase 1 through analysis of the ECR register (Whole System Thinking Phase 1 Report – Section 3.4.2). From the date, duration and number of networks in each archetype it was possible to analyse what proportion of the network is affected due to planned outages. From this, the proportion of network experiencing curtailment calculated under N-1-1 asset ratings and normal (N-1) ratings was determined. From the substation archetype assignment, one EHV rural network in planned outage conditions equates to 0.5% of total rural networks. Therefore for any hour where one EHV rural network is under outage conditions the total curtailment experienced would be a0.5% contribution of curtailment volumes experienced from the abnormal running model and 99.5% from normal running conditions model. This calculation was performed for all planned outages over the entire year.

Whilst this methodology is the most in-depth analysis that could be performed using a parametric model, it is likely an underestimation of the impact of planned outages. At a local level, a single network with derated assets due to a planned outage would experience a much larger increase in curtailment. Transform does not assess the model at a single network level and therefore the contribution of increased curtailment is calculated as proportion of all networks within a voltage level archetype averaging the impact to curtailment.

3.5 Battery Sensitivity

For Stage 2 of the Whole System Thinking project, an assessment of the impact of the current worst case scenario logic around battery load on the network is being performed. To assess this, two sets of curtailment calculations will be produced: one with the current battery load profiles (full charge during periods of demand and full discharge during periods of generation) and a second with a series of profiles that reflect more realistic battery usage. To do this, more probabilistic battery profiles were developed.

EA Technology have previously conducted work analysing domestic battery behaviour and produced more representative ACE-49 style battery profiles for this technology. We will be utilising these for the LV connected battery storage within this sensitivity study. Batteries connected at the grid-scale, however, respond to different signals and therefore behave differently over a 24-hour period than domestic batteries. For battery storage connected at HV and EHV a different set of profiles were developed. Data provided by Baringa for grid-scale battery storage was analysed by EA Technology and a series of load profiles produced.

This report contains a breakdown of the different load profiles produced and methodologies behind their generation. These profiles will then be utilised within the Transform modelling engine to analyse the difference in curtailment experienced by the network when different battery load profiles are assessed.

3.5.1 Domestic Battery 48HH load profile

Domestic batteries are typically used to absorb household demand during peak times and shift this load to off-peak times [13]. Unlike grid-scale batteries, they are less reflective of the variability in demand and generation from sources such as wind and solar but more so to that of the household demand profiles.

[13] Battery storage - Centre for Sustainable Energy (cse.org.uk)

As part of an internal project at EA Technology[14], domestic battery profiles were produced for the winter and summer months. Profiles were developed for the Debut model, a statistical approach (using p and q components) used widely for network design in the UK. It models a realistic worst-case for the network.

The time-period for peak household demand is generally between 4pm and 8pm (with slight variation for the longer days in the summer months). During this time, domestic batteries act to remove some of the peak load (negative load within the profile). The batteries then charge (positive load within the profile) during the night-time when network load is low.

The main difference between the winter and summer profiles is the extension of the negative load period. The increased tail during this period is a direct response to the longer days within the summer periods and therefore an increased spread of evening load during this period. The intermediate cool and intermediate warm profiles were produced to be one third and two thirds respectively between the winter and summer profiles. Throughout a season the behaviour of domestic batteries is consistent to that of household load shifting and therefore a single profile can be used for all three representative days.

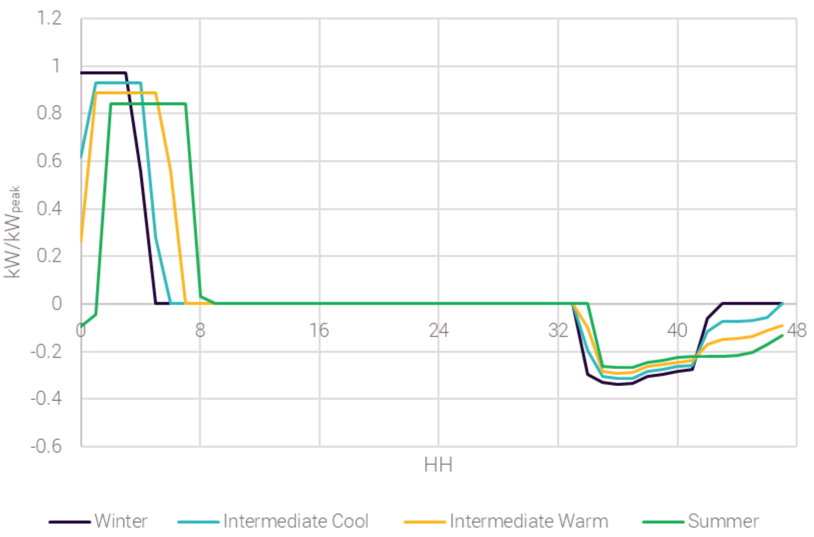


Figure 16: 48HH domestic battery profile for each season.

3.5.2 Grid Scale Battery 48HH Load Profiles

The 48HH load profiles for grid-scale batteries were developed following the same logic as the seasonal generational profiles for wind and solar generation in Section 1 Phase 2 of the Whole System Thinking project. The average hourly dispatch data of approximately 75, 50 MW capacity batteries (based on 3,766 MW installed battery capacity in Baringa's 2023 Net Zero High Scenario) for an entire year was supplied by Baringa for analysis by EA Technology. Each day was averaged to determine

[14] P1.11 - Catherine Birkinshaw-Doyle, Raisa Tahseen Hasanat, Ian Cooper, *Modelling battery storage, vehicle to grid & flexible connections on LV networks*, CIRED Vienna Workshop, 2024.

the total load per day from battery charge and discharge. From this, three representative days could be extracted: a day when batteries had highest demand (charging) characteristics, a day with the highest generation (discharging) characteristics and a day with average charge and discharge behaviour. This mimics the methodology used for other generation sources within this project and produces load profiles for the three representative days used in Transform for each season.

Through discussion with NGED it was determined that the most economical behaviour for grid scale batteries, and thus the more probable, is that on high renewable generation days batteries will be in a charging state more often and vice versa for high demand days. Therefore, conversely to the renewable profiles produced as part of Stage 1 of this project, maximum generation days are dominated by charging load for batteries and high demand days will be dominated by negative (discharging) load.

The 48HH profiles for the three representative days of each season (in which charge is positive and discharge negative) are shown below:

Winter

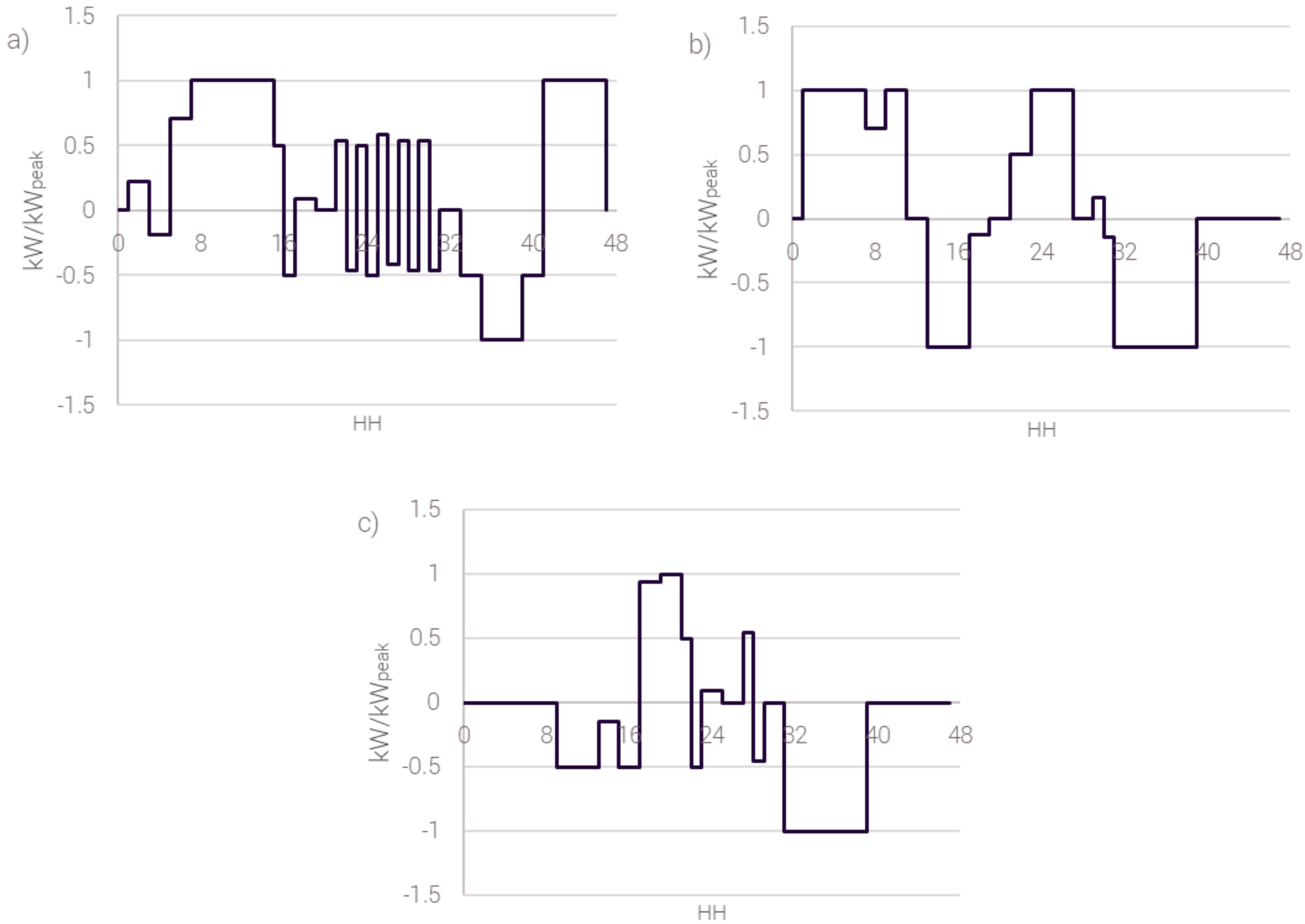


Figure 17: Grid scale BESS profiles for the winter season for a) peak generation day, b) average day, c) peak demand day.

Summer

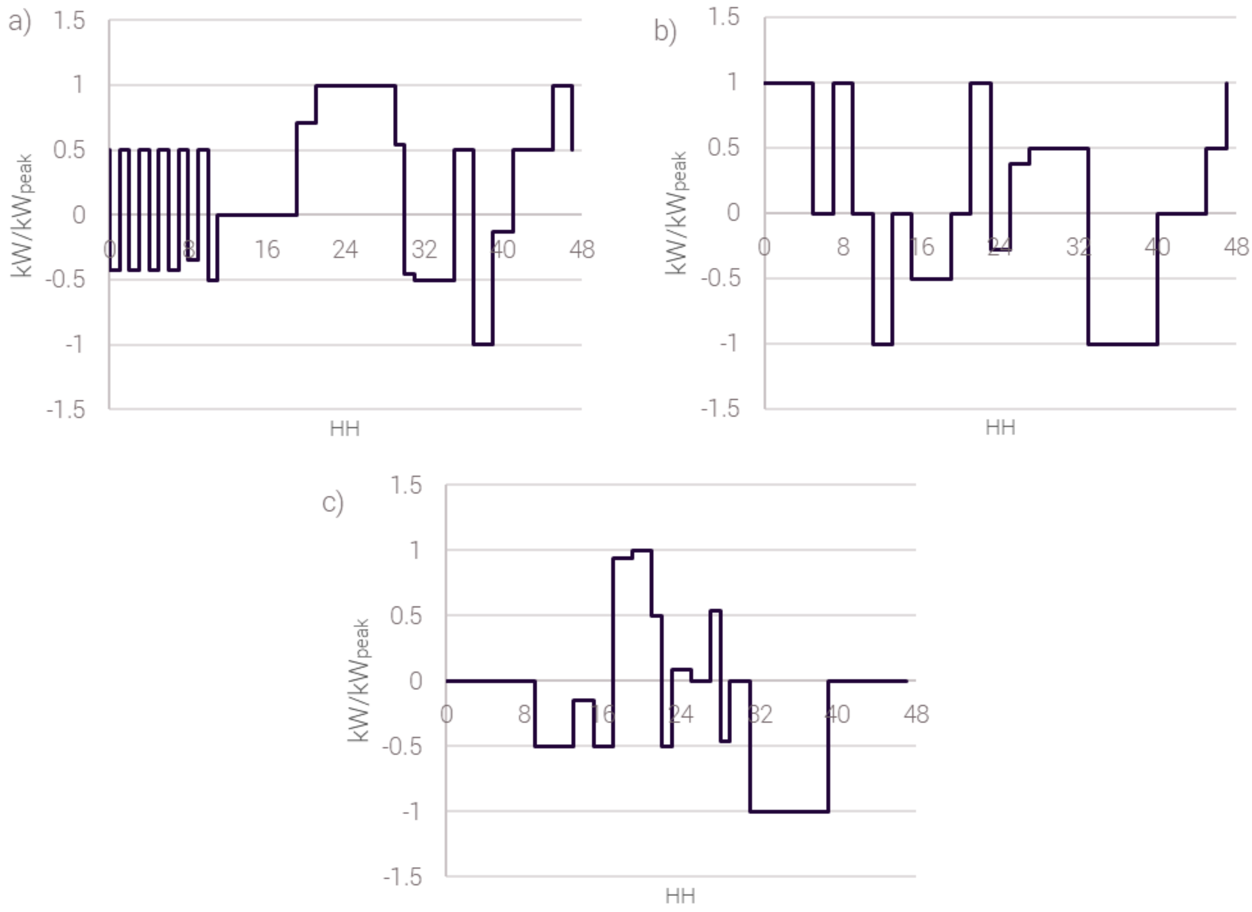


Figure 18: Grid scale BESS profiles for the summer season for a) peak generation day, b) average day, c) peak demand day.

Intermediate Cool

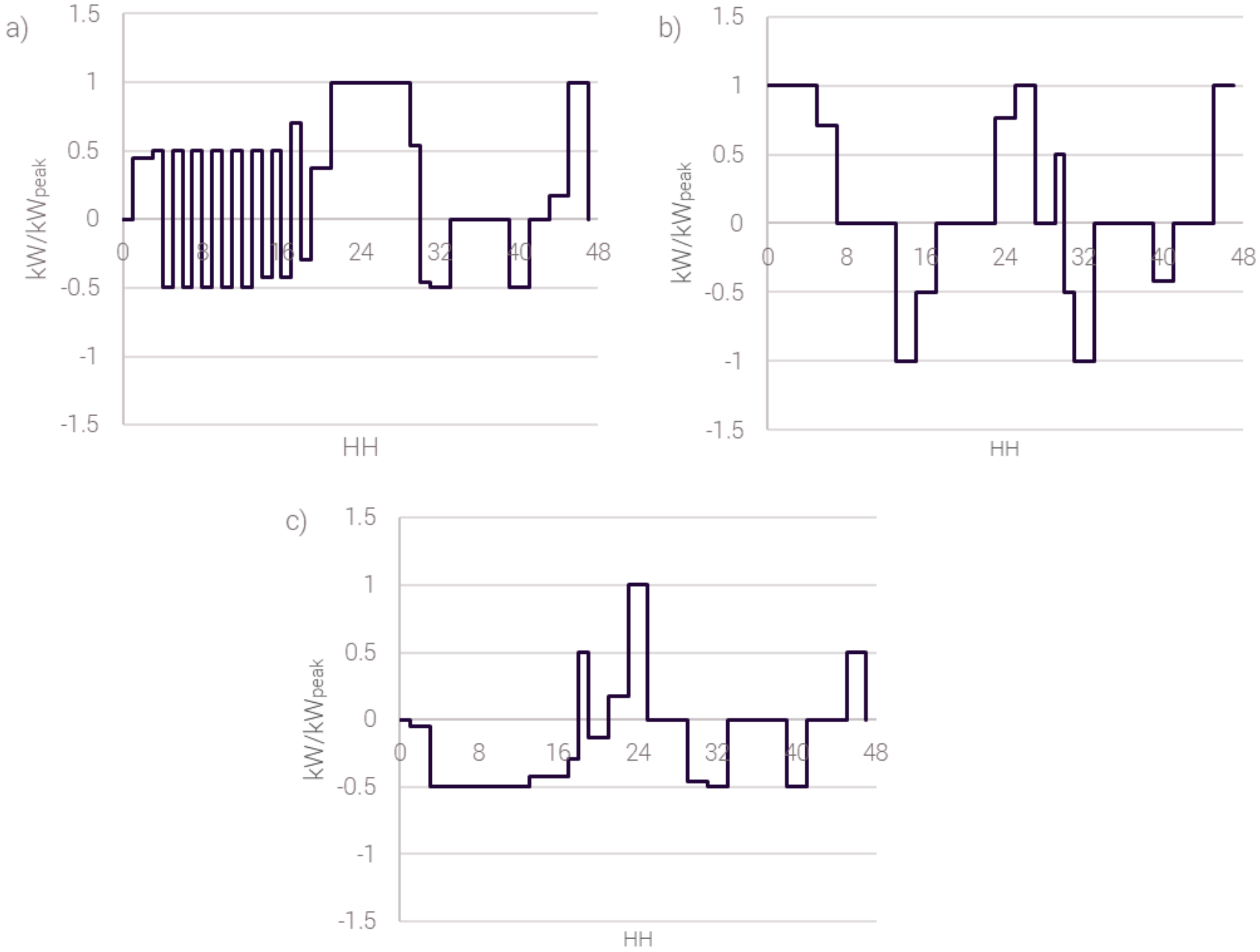


Figure 19: Grid scale BESS profiles for the intermediate cool season for a) peak generation day, b) average day, c) peak demand day.

Intermediate Warm

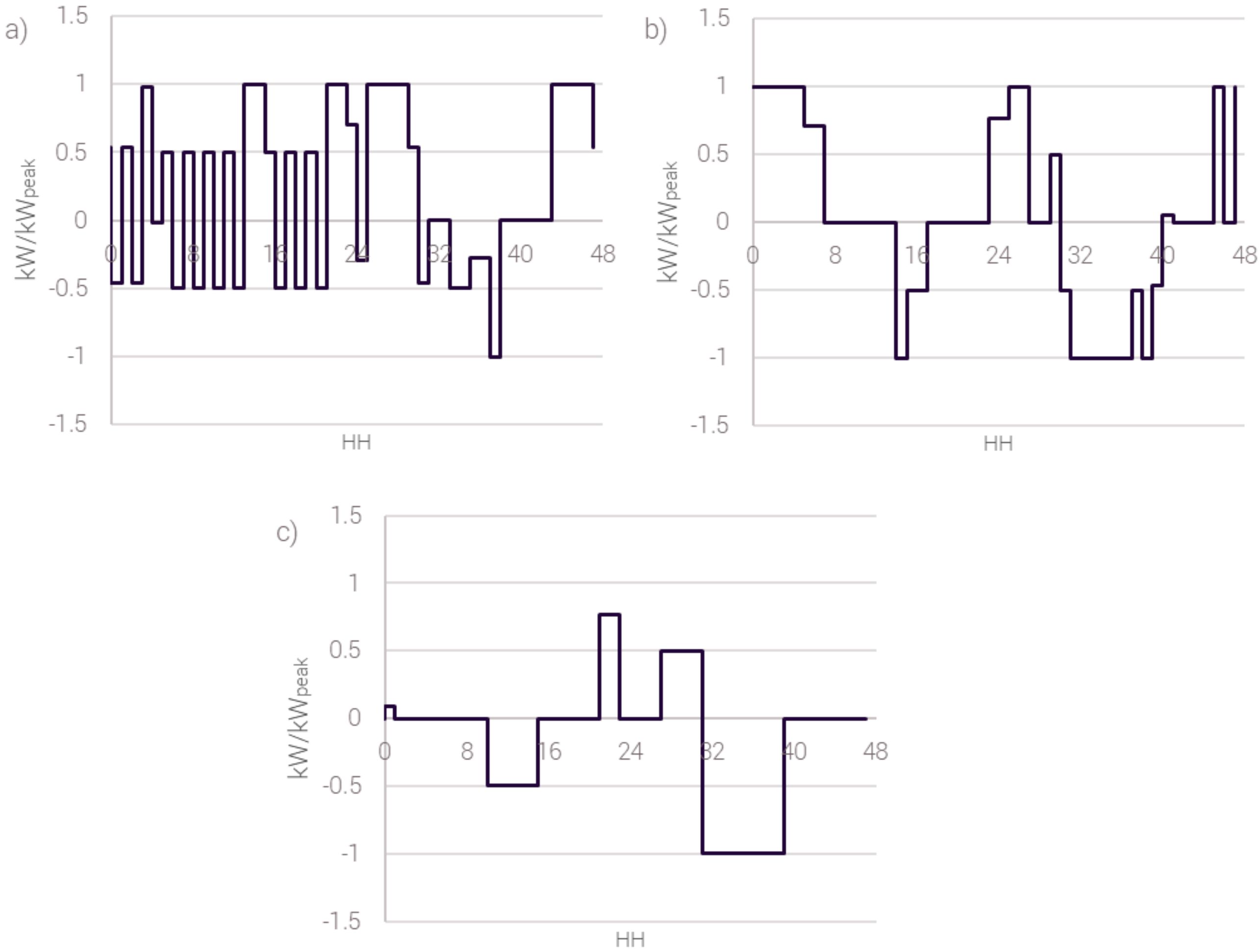


Figure 20: Grid scale BESS profiles for the intermediate warm season for a) peak generation day, b) average day, c) peak demand day.

Impact on overall curtailment results

Assumption	Effect on analysis	Impact on curtailment
Use of 12 representative profiles for grid-scale BESS	The load profile for all days will follow the same twelve patterns, BESS will respond dynamically to market signals. This may lead to over estimations of load during some days and under on others.	Neutral It's very difficult to model BESS behaviour at a grid-scale, due to the very flexible and dynamic nature of it's operation. With economic benefit being a key driver to charge and discharge patterns. Use of set profiles for BESS will likely lead both under and overestimations of curtailment within the modelling. Further to this, the demand load of BESS will also be impacting network reinforcement within the model. If demand is lower, this reinforcement may not occur and thus curtailment will be larger.

3.6 LV-132kV Network Modelling (SCT results combination)

Curtailment on the 132 kV networks was calculated by NGED using their Simple Curtailment Tool (SCT). The proportion of curtailment of solar, wind, batteries and 'other' generators was assessed for 17 of NGED's GSPs (Appendix II highlights the GSPs used for the study). Analysis considering different volumes of attrition (the proportion of connections within the queue that fail to progress) within the connection queues allowed for our study years to be extracted where 2023 has no attrition (only considers connected assets), 2028 had 75% attrition (25% of generators within the queue are connected) and 2034 had 50% attrition (50% of generators within the queue are connected). These assumptions follow the understanding that currently over 60% of connections applications are unlikely to materialise[15].

The SCT considers generation assets connected at the 11 kV and 33 kV voltage levels as well as at the 132 kV. To prevent double counting of curtailment of these lower voltage level connected assets within the 132 kV curtailment volumes, the Transform calculated percentage of curtailment at EHV and HV voltage levels was removed from the SCT results prior to scaling. As Transform is a parametric model and doesn't consider geographical factors, curtailment could be assigned from Transform to each individual GSPs. Instead, it was calculated to an archetype level (rural or urban). Each of NGEDs GSPs was assigned an urban or rural archetype dependent on the BSPs it feeds (Appendix II). From this the Transform EHV archetypes could be topologically connected to the NGED GSPs used in the SCT analysis based on their rural or urban assignment.

[15] What does the ESO's grid connection queue management plan mean? Modo Energy

The curtailment calculated for each technology type at the EHV voltage level was extracted from the Transform results at each hour and apportioned to the rural and urban EHV archetypes based on the clustering assumptions used within the Transform model. From this, a percentage of curtailment at each GSP was assigned to the assets connected at 11 kV and 33 kV and removed from the 132 kV analysis. An example of alignment of the SCT GSPs and the Transform model at 11am on 1st April in the 2034 study year is shown in Tables 16-18 below. By doing this, we ensured that the EHV-132kV boundary between the two different models was aligned and the 132 kV analysis would not count any curtailment we had already calculated within the Transform model.

Table 16: Transform calculated EHV curtailment apportioned to rural and urban feeders on 1st April at 11am.

Date	Time	Archetype	Solar Curtailment	Wind Curtailment	BESS Curtailment	Other Curtailment
01/04	11:00	Total EHV	4%	2%	5%	7%
01/04	11:00	Rural EHV	2.5%	1.5%	2%	3%
01/04	11:00	Urban EHV	1.5%	0.5%	3%	4%

Table 17: The SCT calculated curtailment at the Bushbury GSP (given rural assignment) on 1st April at 11am.

Date	**Time**	**Bushbury Rural Network SCT Curtailment**			
		Solar (%)	Wind (%)	BESS (%)	Other (%)
01/04	11:00	39%	0%	42%	0%

Table 18: The calculated curtailment at the Bushbury GSP (given rural assignment) after removal of curtailment of 11 kV and 33 kV connected assets on 1st April at 11am.

Date	**Time**	**Bushbury Rural Network Final Curtailment**			
		Solar (%)	Wind (%)	BESS (%)	Other (%)
01/04	11:00	36.5%	0%	40%	0%

To scale the data to a GB wide representation, EA Technology first assessed the volume of generation connected or accepted to connect for each of the 17 NGED GSPs and apportioned them into ranges of total connection stack capacity (Table 19). The embedded capacity register (ECR) for four other DNOs, NPg, SSEN, SPEN and UKPN were assessed and total generational capacity for each GSP was calculated. From this, a representative assessment of the proportion of GSPs over different GB areas within the installed capacity ranges could be produced (Table 20).

Based on the representative proportions, the percentage curtailment on the NGED GSPs within each capacity range were weighted to scale the contribution to the total volume of 132 kV curtailment. For example, the 3 NGED GSPs that had total capacity between 750 MW and 1 GW are 18% of the sample GSPs from NGEDs region. However, within the ECR analysis these only make up 9% of the GB wide GSPs, the proportion of curtailment experience on these 3 GSPs therefore is scaled down when calculating the total 132 kV curtailment.

Table 19: The number of NGED GSPs within each of the capacity ranges used in the 132 kV curtailment scaling.

Min Capacity (MW)	Max Capacity (MW)	NGED BSPs
0	**250**	8
250	**500**	2
500	**750**	2
750	**1000**	3
1000	**2500**	2

Table 20: The ECR analysis results for generation connection stack capacity on GSPs with three other GB DNOs.

Min Capacity (MW)	Max Capacity (MW)	UKPN	SSEN	SPEN	NPg	Average	NGED GSPs
0	**250**	44%	83%	98%	12%	59%	47%
250	**500**	22%	4%	1%	28%	14%	12%
500	**750**	13%	6%	1%	16%	9%	12%
750	**1000**	7%	0%	1%	20%	7%	18%
1000	**2500**	15%	7%	0%	24%	11%	12%

To scale the curtailment calculated from the 17 NGED GSPs to an average reflection of the entire GB wide 132 kV voltage level, each of the NGED GSPs was assigned to an installed capacity range and the average curtailment within this range calculated for NGEDs GSPs (Appendix III). To reflect the GB average, the percentage curtailment from the NGED GSPs was scaled to the average GB wide proportion based on the ECR analysis, an example is given below for the 250 – 500 MW capacity range.

Of the selected NGED GSPs, two had a connection stack capacity within the 250 – 500 MW, Bushbury and Pyle. Table 21 gives the SCT calculated curtailment for each technology type on these GSPs at 11am on the 1st April.

Table 21: SCT calculated curtailment on the Bushbury and Pyle GSPs on 1st April at 11am.

Date	Time	Bushbury				Pyle			
		Solar (%)	Wind (%)	BESS (%)	Other (%)	Solar (%)	Wind (%)	BESS (%)	Other (%)
01/04	11:00	36.5%	0%	40%	0%	1%	19%	33%	81%

This means on average the curtailment of NGED GSPs in the 250 – 500 MW range at 11am on 1st April shown in Table 22.

Table 22: Average curtailment on NGED GSPs with a connection stack capacity of 250 - 500 MW on 1st April at 11am.

Date	Time	Solar (%)	Wind (%)	BESS (%)	Other (%)
01/04	11:00	19%	10%	37%	40%

Of the analysed NGED GSPs, the two included within this range make up 12% of the proportion. Based on the ECR analysis of connections queues of other GSPs, the GB average for GSPs within this range is 14%. Therefore the curtailment calculated using the two NGED GSPs required scaling up to be reflected of the GB average. This gives a final GB scaled average curtailment for 250 – 500 MW range GSPs at 11am on 1st April as shown in Table 23.

Table 23: The GB wide scaled curtailment at GSPs on the 132kV network with 250-500 MW connection stack capacity on 1st April at 11am.

Date	Time	Solar (%)	Wind (%)	BESS (%)	Other (%)
01/04	11:00	22%	11%	43%	47%

The curtailment for every half hour at each of the studied GSPs was scaled to be reflective of the GB wide proportion within each capacity range, and proportionally summated (based on the scaling in Table 17) to reflect 100% of the 132 kV network at a GB wide average proportions. This results in a single percentage curtailment for the entire 132 kV voltage level. The total GB average curtailment at the 132 kV voltage level at 11am on 1st April is shown in Table 24 as an example.

Table 24: The average curtailment in each capacity range from SCT calculations on 1st April at 11am.

Date	Time	Range	Solar (%)	Wind (%)	BESS (%)	Other (%)	Scaled proportion within 132kV network
01/04	11:00	<250	3%	0%	3%	1%	59%
		250-500	19%	10%	37%	40%	14%
		500-750	18%	0%	48%	10%	9%
		750-1000	18%	0%	35%	3%	7%
		>1000	13%	38%	70%	32%	11%

Table 25: The scaled GB average curtailment on the 132 kV voltage level at 11am on 1st April.

Date	Time	Solar (%)	Wind (%)	BESS (%)	Other (%)
01/04	11:00	9%	6%	21%	11%

The total volume in kW for each hour of the year was then calculated by multiplying the total GB wide curtailment at the 132 kV voltage level in percent by the volume of installed capacity from FES 2023 System Transformation forecasts for each technology, solar, wind, BESS and 'other'.. This results in a final value of curtailed generation in kW for the four different generation types at the 132 kV voltage level for each hour of every day within the three study years.

Impact on overall curtailment results

Assumption	Effect on analysis	Impact on curtailment
132kV curtailment is calculated based on a representation of all GB wide GSPs.	GSPs will each face individual constraints based on the size of their connections stack. In reality, no GSP will see an average volumes of curtailment; some GSPs will face large volumes of curtailment and some none at all.	Neutral Generators on GSPs with highly volumes of generation connected would typically experience larger volumes of curtailment. Generators on GSPs with low load and lower volumes of generation would likely experience little to no curtailment. Looking at curtailment based on an average GB wide volumes removes the locational specific impacts of curtailment.

R1. While the parametric assessment of curtailment can provide a single 'best-view' based on a series of assumptions, it fails to account for the locationality of constraints, which enables the evaluation of areas anticipated to experience higher volumes of curtailment. To effectively analyse the specific locations where preventing curtailment is most valuable to the networks, it is necessary to develop a connectivity-based tool that predicts expected curtailment due to increased volumes of distributed generation.

3.7 Methodology Conclusions

This methodology aims to accurately reflect the volumes of distributed generation curtailment from LV-132 kV voltage levels. However, predicting forecast curtailment is inherently challenging due to various factors such as governmental policy, supply chain availability and technology costs, consumer behaviour, and other considerations that affect the volumes of connected generation on the network. These in turn influence predicted curtailment volumes. The results presented in this report are based on the assumptions used within the modelling, specifically the application of FES23 System Transformation. Variations would occur if an alternative DER uptake scenario were applied. Recognising the importance of reducing curtailment for consumers, it is anticipated that continued focus and data collection in this area will enhance future assessments, refine forecasting assumptions, and enable the most effective strategies for increasing headroom capacity.

4. Results

The analysis conducted by EA Technology in Stage 2 allowed curtailment to be calculated across LV, HV, EHV and 132 kV voltage levels broken down by four generation types: solar, wind, battery storage and other (including gas, oil, biomass). It assumes that generation technologies are curtailed in proportion to the available generation at the time of curtailment.

EA Technology have provided a series of curtailment outputs to Baringa for use in the economic modelling during the second half of Stage 2 analysis. This section of the report provides a summary of key insights from the network curtailment modelling.

4.1 Best View Curtailment LV-132 kV

The 'Best View' results produced in Stage 2 of this project are based on the curtailment data following application of the assumptions:

- Seasonal load profiles from LV-EHV are as described in Section 3.1.
- All models include V2G technology at FES23 uptake volumes.
- Assets are reinforced following the logic included in Section 3.3.
- LV-EHV networks utilise the variable battery profiles described in Section 3.4, 132kV uses a battery load of 1 kW/kW_{peak} outside of summer and -1 kW/kW_{peak} during summer.
- Other technologies use a load profile of 1 kW/kW_{peak} outside of summer and -1 kW/kW_{peak} during summer.

4.1.1 Phase 1 comparison

During Phase 1 of the Whole System Thinking Project EA Technology used their Transform network modelling tool to calculate potential curtailment on the LV-EHV networks. To do this, DFES load profiles from four representative days (Winter, Summer, Intermediate Cool and Intermediate Warm) were utilised to represent a whole year. As the DFES load profiles are used to assess the worst case within each of the four scenarios, the only season that considers generational load is Summer. The other three seasons are demand focused, resulting in curtailment only being observed in June, July and August within the Phase 1 analysis. Whilst it is expected that curtailment will be greater in the summer months, it is expected that curtailment could be experienced all year round. To produce a better year-round reflection of curtailment, Phase 2 considered twelve representative days in total. These consisted of three load profile days (peak demand day, average day, and peak generation day) for four seasons (Winter, Summer, Intermediate Cool and Intermediate Warm).

The results in Figure 20 show the daily curtailment in the three study years comparing the results of both phases. The updated modelling profiles used in Phase 2 results in curtailment being experienced on the LV-EHV network in every season giving a far more appropriate representation of network curtailment. Curtailment is not only witnessed over a larger portion of the year but also in greater volumes. This is because generation from all modelled generation technologies are considered in all representative days.

Unlike in Phase 1, curtailment calculated in Phase 2 of this project for the LV-EHV networks considers the requirement of networks to reinforce the network for demand growth. In Phase 1, curtailment was assessed against fixed base year asset ratings. For Phase 2, the modelling considered network reinforcement in response to demand constraints and upgraded asset ratings as a result. Despite increased asset ratings due to demand reinforcement there was still an increase in the curtailment volumes experienced during Phase 2 analysis. This highlights that whilst the need to reinforce for customer demand is still important, to allow for full penetration of distributed green energy resources on the network consideration must also be made to ensure the network is prepared ahead of need for generational requirements.

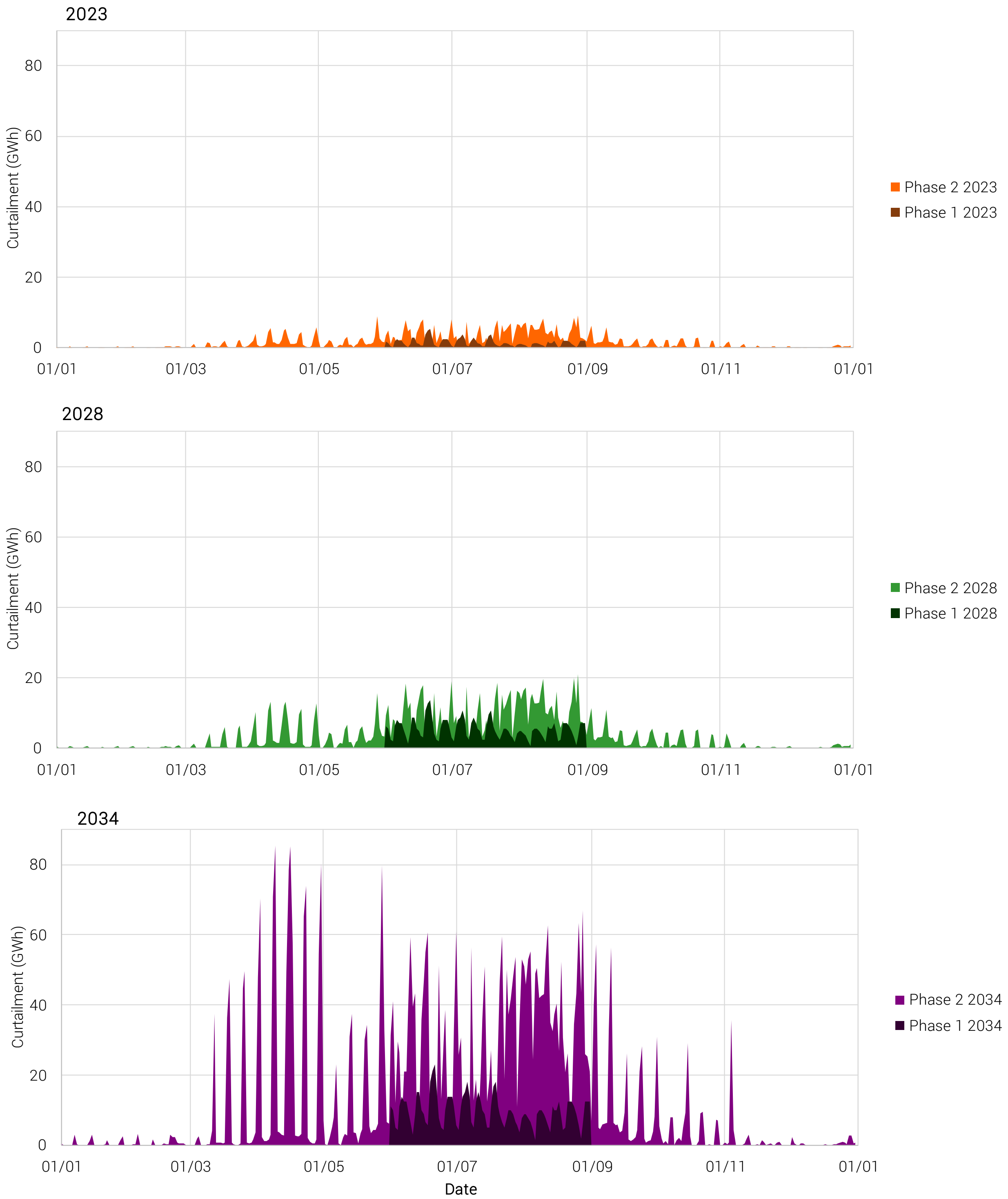


Figure 21: Total daily curtailment on the LV-EHV networks from the Transform curtailment analysis comparing Phase 1 and Phase 2 results.

Note: Even within the Stage 2 analysis curtailment is still experienced in similar patterns between each study year due to the use of representative days scaled to a year.

4.1.2 Curtailment volumes by generation type

In 2023, 57% of the total volume of generation curtailment is from generator types within the other category (gas, oil, biomass). By 2034 however this changes with 57% of all curtailment being attributed to solar curtailment. Figure 21 shows the varying proportions of curtailment on the network in 2023 and 2034.

Whilst the generator types within the other category contribute most of the curtailment in 2023 and 2028 it is important to remember that most of these generators will be large plants connected to the higher voltage levels such as the 132 kV networks. Within the SCT, generators within the other category are assumed to contribute a maximum generational load to the network at all times, likely overestimating the available yearly energy available of these sources over the year. In most cases however, it is unlikely that these generators will behave in this manner as most 'other' sources will be in the form of dispatchable generators which most commonly will only dispatch when it is economically sensible. As a result of the increased available energy from these generators, they are also applicable to be curtailed at all periods of the year. This will may lead to an overestimation of the curtailment experienced by generators in the other category on 132 kV networks.

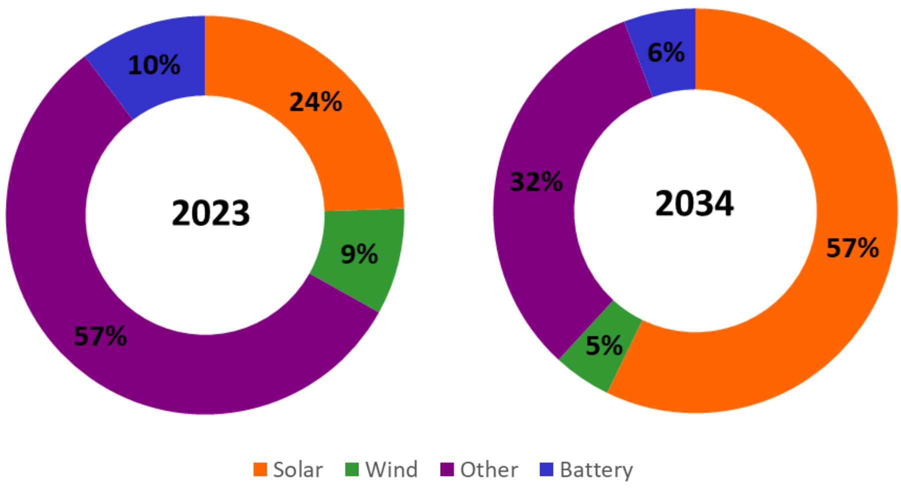


Figure 22: The proportional split of curtailment in 2023 and 2034 per generator type.

Figure 22 shows the total annual curtailment of each generation technology in 2023, 2028 and 2034. There is an increase in the volume of curtailment experienced for solar, wind and battery storage between each year of the study period. Unlike the other three generation types, the other generator type increases to 2028 and then decreases to 2034. This is likely a result of the decreasing volumes of gas on the network as a proportion of total generation by 2034.

By 2034, the total annual curtailment across included technologies on the distribution network is calculated at 8.5 TWh, enough electricity to power just under 3.2 million (11%[16]) UK homes for a whole year[17].

[16] Assuming approximately 28.4 million UK households. Taken from ONS data: [Families and households in the UK - Office for National Statistics]

[17] Assuming a typical UK household electricity consumption of 2,700 kWh annually. Taken from Ofgem data: [Average gas and electricity usage | Ofgem]

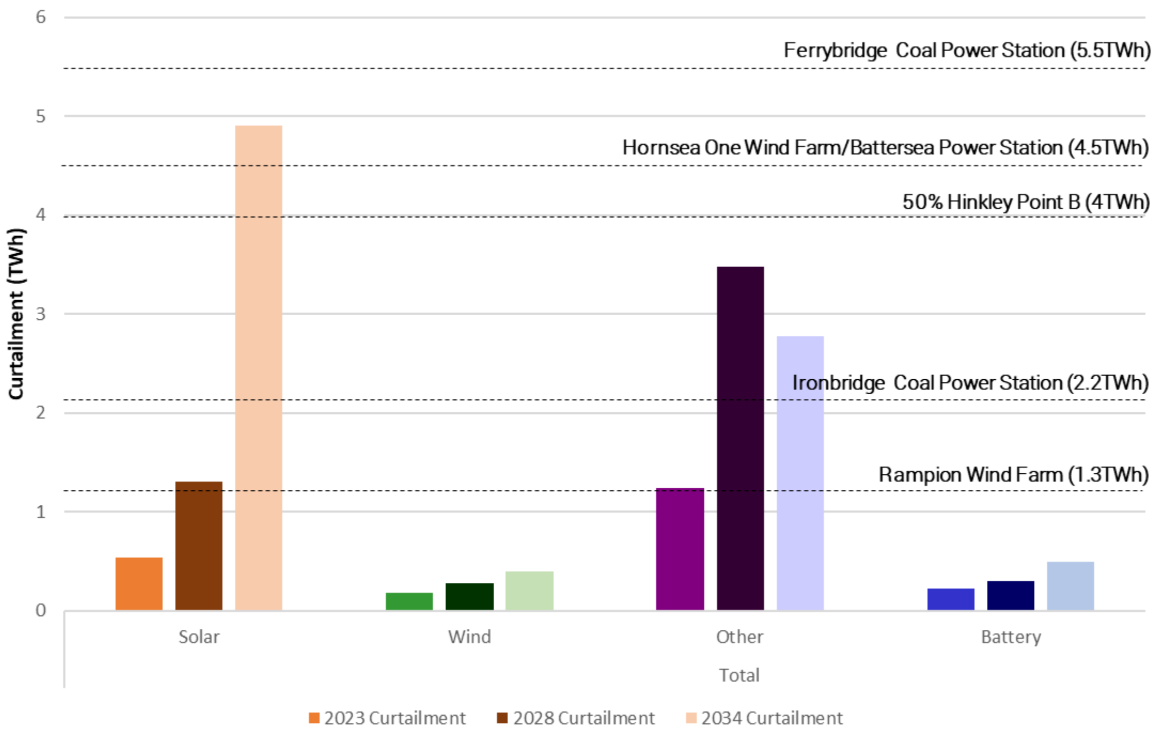


Figure 23: Total annual curtailment in GWh for the four generator categories in 2023, 2028 and 2034. Curtailment volumes are compared to the generation capacity of some UK based power stations.

In this study, wind in all years experienced the lowest curtailment volumes. This may oppose initial expectations due to common reports of increasing curtailment of wind generation in the UK. However, these results reflect the following assumptions:

- Only distribution connected onshore wind was considered during the analysis. Most of the onshore and offshore wind generation connects at transmission level. This reduces the volumes of wind generation deployed within the study.
- Transform analysis considered a bottom-up approach to network load analysis. Therefore, top-down curtailment (where constraints on the higher voltage levels result in curtailment of lower voltage connected generators) is not considered. A distribution connected wind farm on the Scottish border may be curtailed due to constraints on the B6 transmission boundary.
- The uptake volumes for this study were sourced from FES 2023. This means the change to governmental policies removing the de-facto ban on onshore wind developments in England, announced in July 2024, was not considered in the volumes of onshore wind forecasted.

It is expected that uptake rates of onshore wind over the next decade will increase compared to the volumes used within this study.

C2. By 2034, the forecast solar curtailment across the LV-132kV voltage levels is 4.8 TWh this equates to 1.8% of the UK's total current electricity need and 1.2%[18] of predicted electricity demand in 2034.

C3. Based on the methodology assumptions, the total calculated volume of curtailed generation on the distribution network in 2034 is 8.5 TWh, enough electricity to power 3.2 million homes for a year in the UK.

R2. To enable the potential consumer cost benefits of changing onshore wind policies and increased wind generation, networks must consider how connection queue lengths may delay the availability of potential onshore wind capacity.

The average curtailment per day for each technology type across all voltage levels are shown in Figure 23: Average curtailment over 24 hours for each generator type in 2023, 2028 and 2034.. As in Phase 1 of this project both in average volumes and profile curtailment in general aligns with peak solar generation. Wind, gas and battery storage all see an increase in curtailment during the middle hours of the day enforcing the impact of PV as a driver of curtailment. By 2034, at 12pm there is respectively 20, 5.2, and 16 times more curtailment of solar on average than wind, gas or battery storage.

Unlike solar, which outside of daylight hours does not generate, wind, gas and battery storage all experience a base volume of curtailment at all hours of the day in the modelling. This aligns with the expected behaviour of these technology which have the potential to generate during all hours of the day.

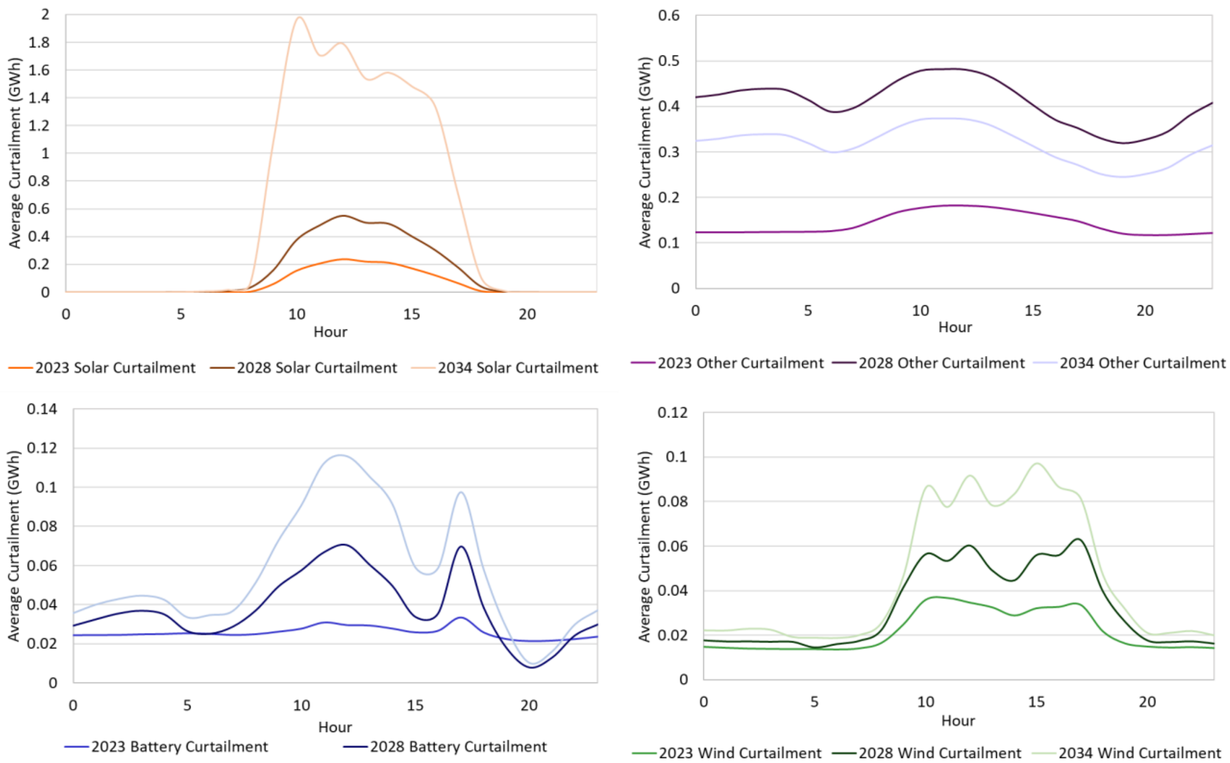


Figure 24: Average curtailment over 24 hours for each generator type in 2023, 2028 and 2034.

18 Assuming approximately 400 TWh of electricity need by 2034 annually.

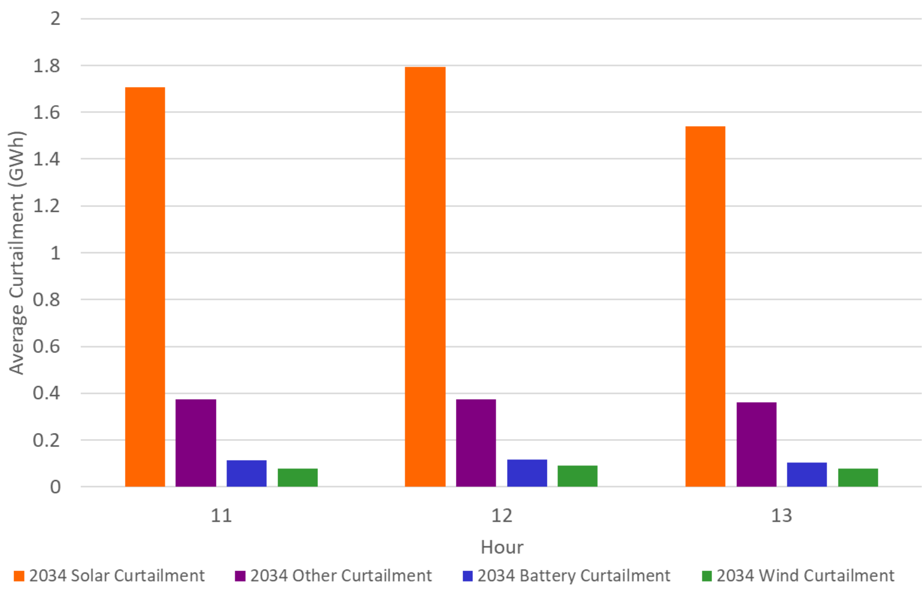


Figure 25: Comparison of the volumes of curtailment at 11:00, 12:00 and 13:00 in 2034 for the four different generator types.

C4. Solar is expected to be the primary driver of curtailment on the distribution network with all technologies seeing an increase in curtailment volumes during daytime hours as a result. This is largely a reflection of the high forecast for installed solar capacity. At a domestic level (LV) this curtailment will be experienced as voltage rise constraints preventing domestic solar from generating freely.

C5. The new governmental policy lifting restrictions on onshore wind development may result in larger volumes of wind curtailment than forecasted in this study due to increased volumes of onshore wind generation connecting to the network.

4.1.3 Voltage Level

In 2023 and 2028, curtailment is primarily experienced on the 132 kV network with respectively 73% and 76% of total distribution network curtailment at this voltage level. By 2034, the LV network experiences the highest volume of curtailment at 50%. As discussed in the previous section, the proportion of curtailment experienced by voltage level is a result of the generation mix within each voltage level. Curtailment at the LV level is dominated by the large volumes of solar generation connected at a domestic level. Whereas the 132 kV network is dominated by larger generation sites such as gas generators contained within our other category. By 2034, the installed volume of these large generators is expected to drop relative to distributed sources such as solar and therefore there is a decrease in the volume of energy curtailed at the 132 kV voltage level.

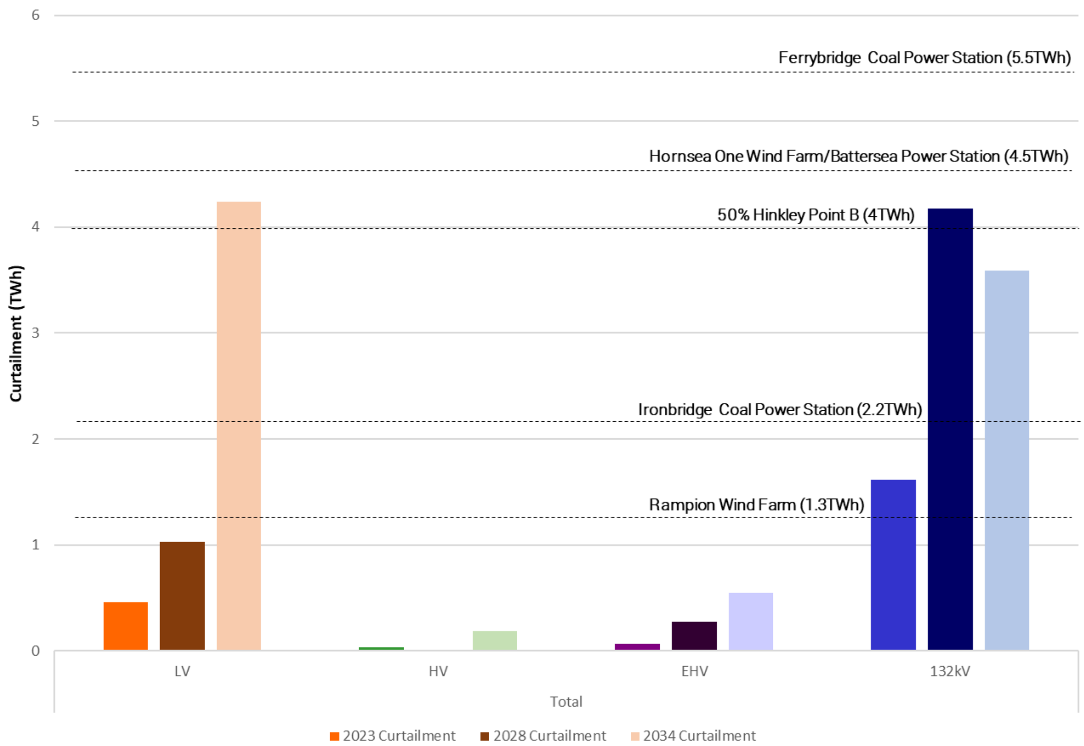


Figure 26: Total annual curtailment in GWh for the four voltage levels in 2023, 2028 and 2034. Curtailment volumes are compared to the generation capacity of some UK based power stations.

LV Network Curtailment

The calculated annual volume of energy curtailed on the LV network is 0.46 TWh, 1.03 TWh and 4.24 TWh in 2023, 2028 and 2034 respectively (Figure 26). The large volumes of expected solar on the LV level has the biggest impact on the curtailment observed with larger volumes in the summer season in all study years (Figure 27).

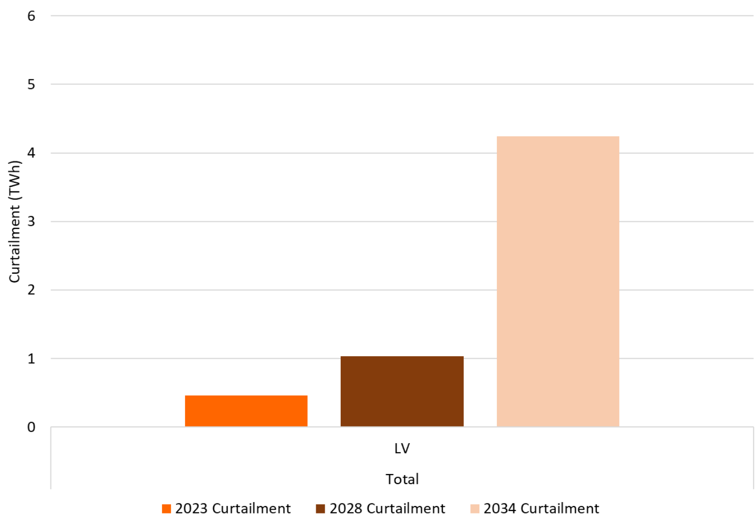


Figure 27: Volumes of curtailment at the LV voltage level in 2023,2028 and 2034.

Unlike at the higher voltage levels, the LV network is not under Active Network Management (ANM) schemes. When we discuss curtailment at the LV level within this study, we are considering distributed generation as unavailable due to the network assets being unable to absorb the generational load. When analysing the constraint types occurring from generation on the LV level within the Transform analysis, 80% of all constraint types were due to voltage headroom (where thermal constraints did occur, a voltage constraint was also occurring in the modelling). In these instances of voltage limit constraints on the network domestic generation sources such as solar would trip and therefore be unavailable to generate. Without consideration of the impact of generation on LV assets customer satisfaction and their likelihood to adopt technologies such as solar may decrease.

Further to this, within Transform LV assets are rated so that they have a larger capacity for voltage drop, reflecting the demand focus of these networks and the legal requirement of networks to always have sufficient capacity to meet demand on the network. This reflects how historically the tap position within transformers is near the top of the voltage range to apply for maximum voltage drop along a feeder length. However, this means that the voltage rise capacity within Transform is reduced, leading to a potential overestimation of the occurrence of voltage rise constraints and thus generation curtailment.

Within the modelling, the asset ratings at the LV network were reinforced when a demand constraint was experienced but not for generational constraint (see Section 3 for methodology). As a result, by 2034 the rating of the assets will have increased compared to 2023. Even with the demand reinforcement on the assets the LV network is still experiencing increasing volumes of generation curtailment year on year.

Without consideration ahead of need for increasing generation on the LV network, customer satisfaction and their likelihood to adopt LCTs may decrease due to reliability concerns.

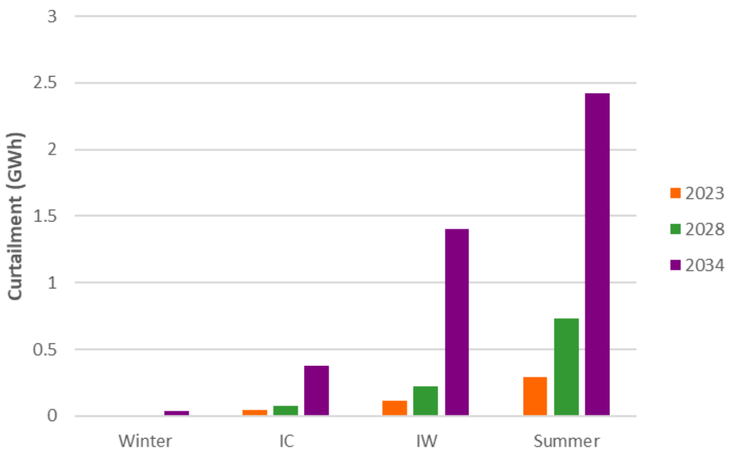


Figure 28: Calculated LV curtailment within each season in 2023, 2028 and 2034.

C6.	By 2034 as volumes of domestic solar increase, curtailment on the LV network surpasses that of the higher voltage levels.

R3. Consideration into the impact of changing tap positions to increase voltage headroom and reduce curtailment on KV networks should be considered. This must be balanced however with the potential increase in voltage drop issues and the associated network reinforcement requirements.

HV Curtailment

The calculated yearly volume of energy curtailed on the HV network is 0.03 TWh, 0.003 TWh and 0.18 TWh in 2023, 2028 and 2034 respectively.

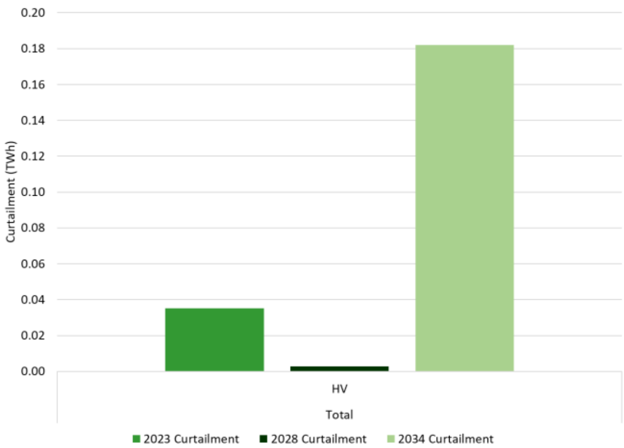


Figure 29: Volumes of curtailment at the HV voltage level in 2023,2028 and 2034

Within this study the HV networks experience the lowest volume of curtailment. This is due to a combination of the volumes of installed generation and the asset ratings of the HV networks within the Transform modelling. The main example of this is the voltage headroom rating. In Transform the HV networks are assumed to have some level of automatic on-load tap changing capabilities and therefore sit within the centre of the voltage window (+6% headroom). This means that the assets within HV network have more capacity to absorb generational load than experienced at the LV network within the modelling. Furthermore, the asset ratings within Transform at the HV network are larger, leading to increased headroom on average. This means larger volumes of generation can be connected (particularly on urban and suburban networks) before constraints are experienced (Appendix III explains the HV archetype ratings in more detail). Due to the parametric nature of the Transform modelling, curtailment therefore may be being underestimated on the HV network due to presence in reality of networks with less available voltage headroom or very localised, large volumes of connected generation that is not represented within the Transform methodology.

The HV networks within the Transform modelling followed the same demand reinforcement logic as the LV network, with asset ratings increasing due to demand constraints but not with generation. The effect of network reinforcement is shown in Figure 29 with a decrease in the volume of curtailment between 2023 and 2028. As the rate of generation installed on the network increases between 2028 and 2034 the volume of curtailment also increases.

As with the LV network, curtailment occurs most commonly in the summer months and is a reflection of the generational mix connected at this voltage level having a larger volume of solar than other generator types.

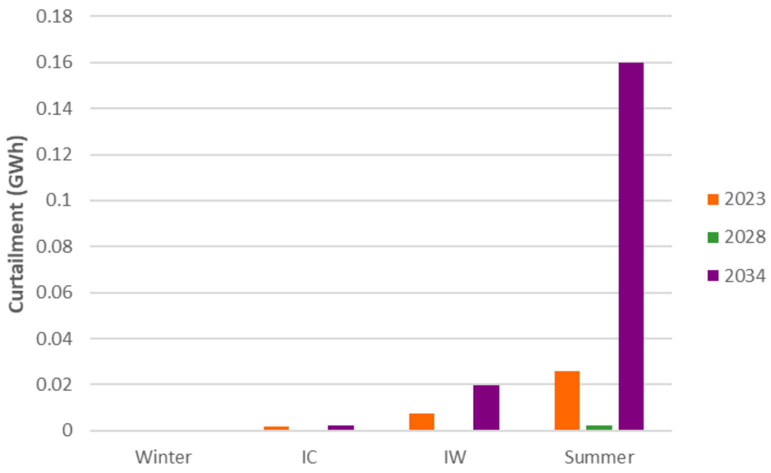


Figure 30: Calculated HV curtailment within each season in 2023, 2028 and 2034.

EHV Curtailment

The calculated yearly volume of energy curtailed on the EHV network is 0.1 TWh, 0.3 TWh and 0.5 TWh in 2023, 2028 and 2034 respectively.

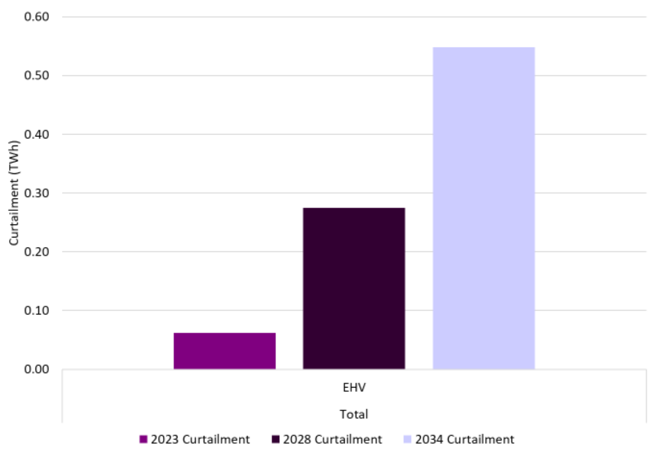


Figure 31: Volumes of curtailment at the EHV voltage level in 2023,2028 and 2034.

As with the HV network, the curtailment calculated on the EHV networks is likely an underestimation. This again, is due to the relationship between installed capacity and asset ratings within the parametric network model. Networks with less available voltage headroom or very localised, large volumes of connected generation will exist and may experience large volumes of curtailment not represented within this modelling methodology. To better understand the impact of these extreme networks, development of a specific connectivity-based curtailment calculation tool is needed.

Whilst curtailment is still higher in the summer season, the EHV network experiences a larger volume of curtailment in the colder seasons than observed at LV and HV levels. This is due to the large volumes of other generation sources such as wind and gas which will continue to generate outside of the summer months.

The curtailment calculated in the winter season decreases from 2023 and 2034 in response to increasing asset ratings due to demand reinforcement releasing more capacity than the increasing volumes of technologies that generate outside of the summer (i.e., not solar). Outside of the winter season, curtailment increases between 2023 and 2034. This is likely a result of the volumes of solar generation on archetypes with high levels of distributed generation growing faster on these networks

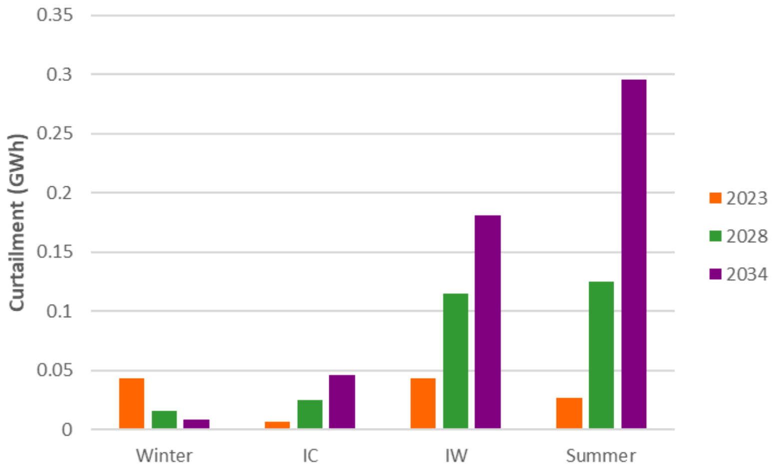


Figure 32: Calculated EHV curtailment within each season in 2023, 2028 and 2034.

than the growth in demand.

C7.	The EHV network experiences larger volumes of curtailment outside of the summer that LV or HV networks due to the greater mix of installed generation on the network, particularly LCTs such as wind generation and battery storage.

R4.	To better represent the extremes of the network, that may have large volumes of localised generation and thus experience greater volumes of HV and EHV curtailment a connectivity-based model specifically developed for forecasting network curtailment is needed.

132 kV Curtailment

The calculated annual volume of energy curtailed on the 132 kV network is 1.6 GWh, 4.2 GWh and 3.56 GWh in 2023, 2028 and 2034 respectively. The curtailment on the 132 kV network is more evenly distributed across the entire year. This is due to the larger proportions of wind, battery storage and other generation types on the 132 kV network. As discussed in Section 1, other generation types have a constant load profile in the 132 kV analysis, as does battery energy storage. Therefore, the generation from these generator types is available all year round and therefore may be curtailed at any point in the year. The use of these load profiles results in an overestimate of curtailment on the 132 kV network from the installed capacity of these two technology types, since they do not generate constantly in real-world application and instead are more likely to respond to market price signals.

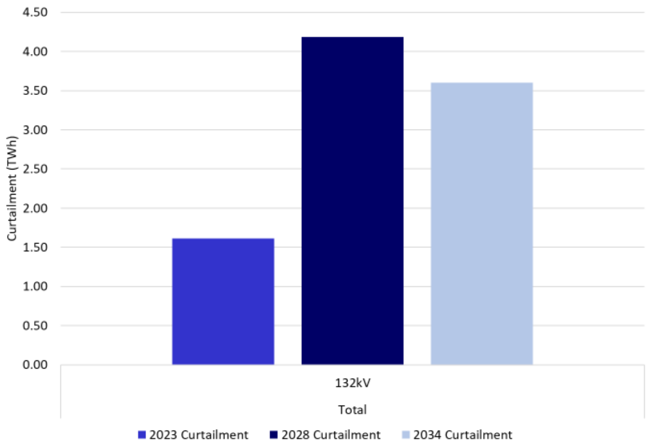


Figure 33: Volumes of curtailment at the 132 kV voltage level in 2023,2028 and 2034.

Between 2028 and 2034 the volume of curtailment decreases on the 132 kV networks. In the curtailment analysis the SCT produces curtailment as a percentage value. The associated energy curtailed is therefore calculated in relation to the volume of installed capacity on the network. Between 2028 and 2034, the gas generator capacity installed on the network decreases, as capacity for renewable technologies such as solar increase. As the 132 kV network has a smaller portion of installed solar than at other voltage levels, the loss of gas generation isn't directly replaced with solar, resulting in a reduction in total GWh of curtailment even though curtailment volumes as a percentage increase at individual GSP sites. Additionally, the load from gas at the 132 kV voltage level is at a maximum all hours of the year within the modelling, whereas solar has a seasonal contribution. This inflates the impact of reduction in gas generators volumes on curtailment.

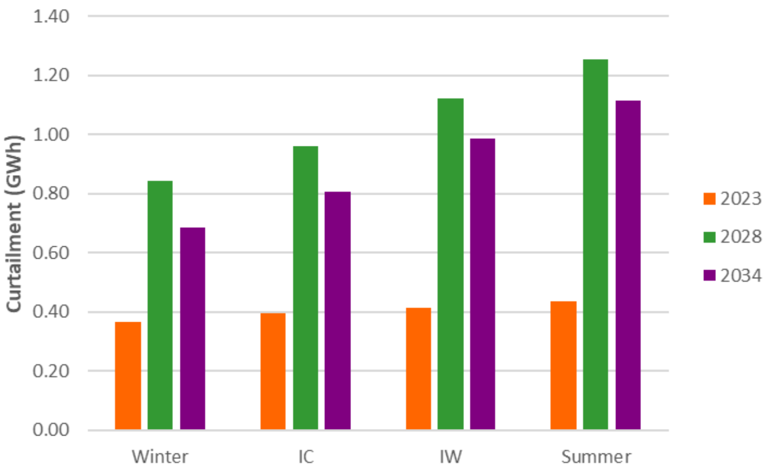


Figure 34: Calculated 132 kV curtailment within each season in 2023, 2028 and 2034.

Unlike the LV network, the HV, EHV and 132 kV networks are available to ANM services. The increasing volumes of curtailment of these networks calculated in this study pose a threat to the likelihood of generators wanting to connect to the network. If generators are being offered curtailable connection agreements with extremely high volumes of curtailment, they may be reluctant to connect leading to loss of generators or delays in connection whilst generators wait for firm connections. This not only results in potential reductions in customer satisfaction but could also prevent decarbonisation targets being met.

C8. The 132 kV network experiences higher volumes of predicted curtailment outside of the summer months than other voltage levels due to a more varied generation mix with greater volumes of wind and gas generation.

R5. Development of a load flow curtailment estimator will allow for calculation of more accurate curtailment values for generators increasing customer satisfaction and enable more LCT generation connections.

4.2 Battery Load Profile Sensitivity

Within this study a sensitivity analysis on the impact of modifying the assumptions of BESS load profiles was performed. To understand the difference in calculated curtailment two Transform models of the LV-EHV networks were developed:

1. A model with the original Stage 1 assumption on battery behaviour for BESS profiles, fully charging on peak demand or average days and fully discharging on peak generation days.
2. A model with updated BESS assumptions as discussed in Section 3.5 of this report.

The calculated difference in the total annual energy curtailed between the updated and original models is shown in Figure 20. In both the 2023 and 2034 analysis, the volume of curtailment calculated for all technology types is lower within our updated analysis. This is a direct result of the reduction in generation from batteries on peak generation days due to the updated BESS assumptions. Removal of the constant generation from batteries on peak generation days in 2023 and 2028 decreases the overall volume of curtailment that is experienced on average during the day.

By 2034 however, there is a general reduction in the difference between the updated and original curtailment results. Whilst wind and batteries are still reduced in curtailment, due to their higher generation volumes outside of summer months and more variable daily load profiles, solar and other generator types both see an increased volume of curtailment by 2034 with the updated load assumptions. This general decrease can be explained due to several factors.

Firstly, the grid scale BESS load profiles used in the updated load analysis were produced from market load data made available to EA Technology by Baringa. Within all these profiles, BESS is acting as a generator during peak times. This is likely a result of battery behaviour reflecting the most favourable economic gain for the battery operator, regardless of whether this is beneficial to the network or long term to consumers. If it is more financially favourable for batteries to curtail, they may do so before generators such as gas that are more costly to the consumer. Furthermore, there may still be a financial benefit of exporting at peak times to respond to network demands even if other cheap generation sources are available as the price per kW to charge may still be cheaper during periods of low demand regardless of the generation available. As a result, the curtailment results for 2034 increases in the modelling for solar and other generators that within our model are more available during periods of peak demand on the network (17:00-18:00). Whilst the overall curtailment is lower in 2034 for wind and batteries, the increased volumes of curtailment at peak demand periods still see a reduction in the delta between models in 2034.

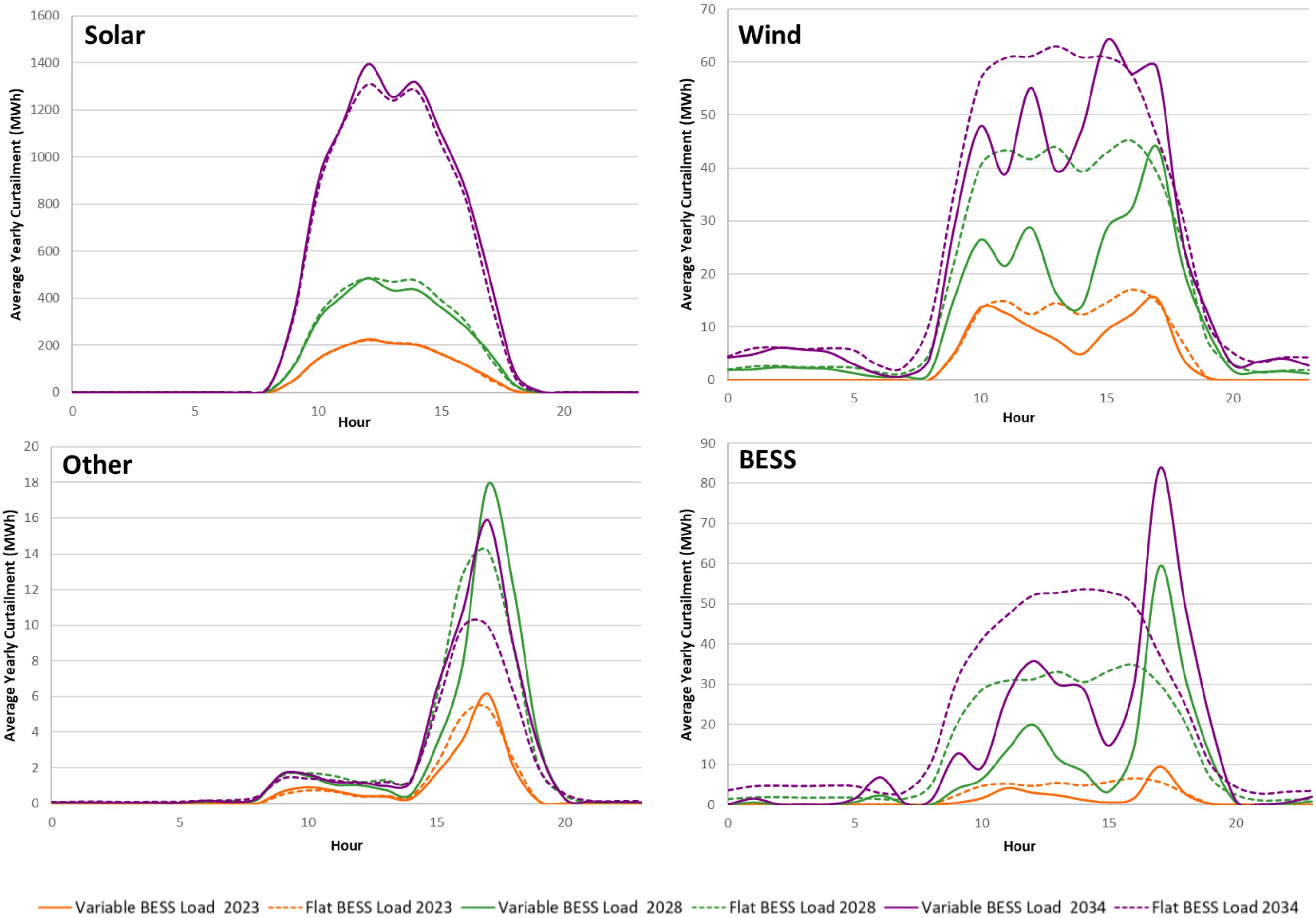


Figure 35: Average curtailment at each hour of the day for the different generator types in 2023, 2028 and 2034, new variable BESS load profile model (dashed lines) and previous flat BESS load profile model(solid lines).

Secondly, whilst the updated load profiles of BESS technology are important, the volume and proportion of different connected generation at each voltage level also effects calculated curtailment. Within the LV networks the volume of BESS connected based on the ECR analysis of phase one is minimal with 99% of connected generation being solar in all study years. This means that variance to the load profiles has minimal impact on the volumes of curtailment. It is likely that there will be a large proportion of domestic BESS however the bulk function of this technology will be to support household demand behind the meter and will therefore have minimal impact on asset constraints.

If domestic batteries were to have larger participation into export tariffs in the future, the predicted impact of our updated load profiles would be an underestimation, with a larger reduction in volume of curtailment expected due to our updated load profiles. At the higher voltage levels (HV and EHV), the proportional split between technology types is greater and not solely dominated by solar generation. As a result, the relationship between the availability of these technologies at a given time and volumes of curtailment experienced increases, meaning the variance in load profiles has a greater impact at the higher voltage levels.

Finally, as discussed in Section 3, the updated analysis considered required demand reinforcement within the curtailment calculations. As all BESS within the original model acted as a demand load on days outside of peak generation, it is likely networks with higher volumes of connected BESS were reinforced due to demand requirements earlier, or to a greater volume in the original modelling than in the updated modelling. The large variance in HV curtailment of the two models between 2028 and 2034 is likely a direct result of increased demand reinforcement in the original model resulting in a reduction in curtailment experienced and therefore a positive delta in the comparison between the original and updated curtailment models in 2034.

The decreased levels of demand reinforcement experienced in the updated load profiles, is likely a response to the updated BESS profiles, discharging more on high demand days, absorbing some of the peak load and therefore reducing overall demand within the model.

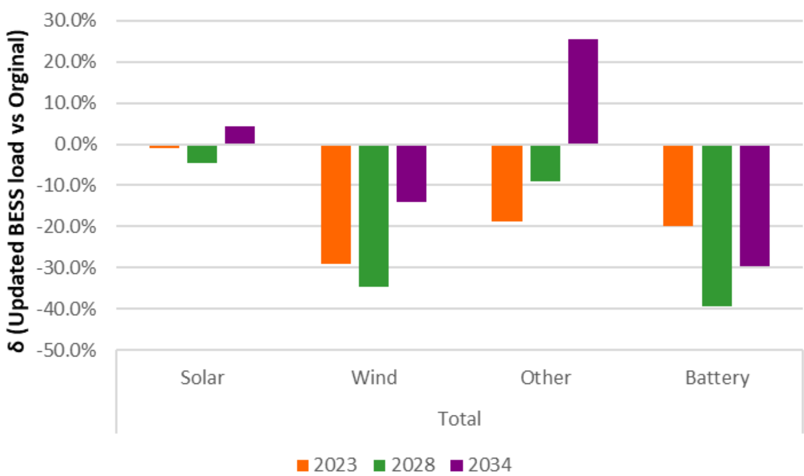


Figure 36: Comparison on the difference in curtailment experienced for each technology type with updated BESS load profile assumptions.

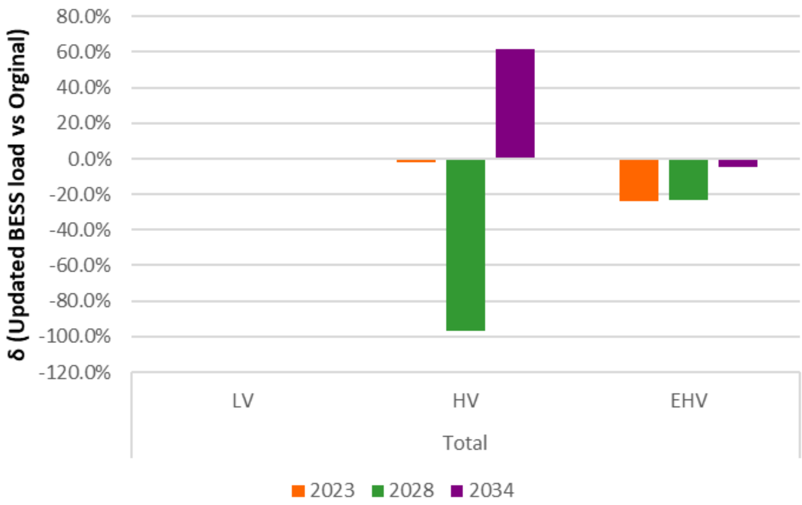


Figure 37: Comparison on the difference in curtailment experienced for each voltage level with updated BESS load profile assumptions.

C9. Changing assumptions around BESS load reduced the volume of curtailment calculated on the EHV voltage level within the three study years.

C10. The HV network experiences a varied impact on curtailment, decreasing in 2023 and 2028, but increasing in 2034; this is likely a result of delayed demand reinforcement with less battery demand load from BESS in the new load profile model.

C11. The minimal proportion of installed BESS on the LV network results in negligible change to curtailment through varying the load profile.

C12. The relationship between assumed load on the network and associated demand reinforcement is impacted greatly by changing BESS load.

R6. When reviewing the impact of battery energy storage on consumers and the network, the response of batteries to both economic signals (high whole price for electricity) and network signals (curtailment due to network overload) must be considered.

R7. A combined network and economic model to anticipate the behaviour of BESS on the network and the potential benefits or costs to consumers is needed to help direct policy behind battery storage behaviour at the grid scale.

4.3 Abnormal Network Running Conditions

The outage data utilised for Stage 2 of the modelling contained network outage data for the HV and EHV network. The bulk of the planned outages included in the database were on the EHV voltage level, therefore the analysis in this section primarily focuses on the impact to curtailment on the EHV network by considering planned outages.

Over the three study years, the volume of curtailment increases on average 2.9% when abnormal running conditions are considered. The additional volume of curtailment decreases slightly each study year as more networks at the EHV voltage level are reinforced due to demand and therefore the volumes of curtailed generation above the asset ratings decreases slightly across both models (Figure 37).

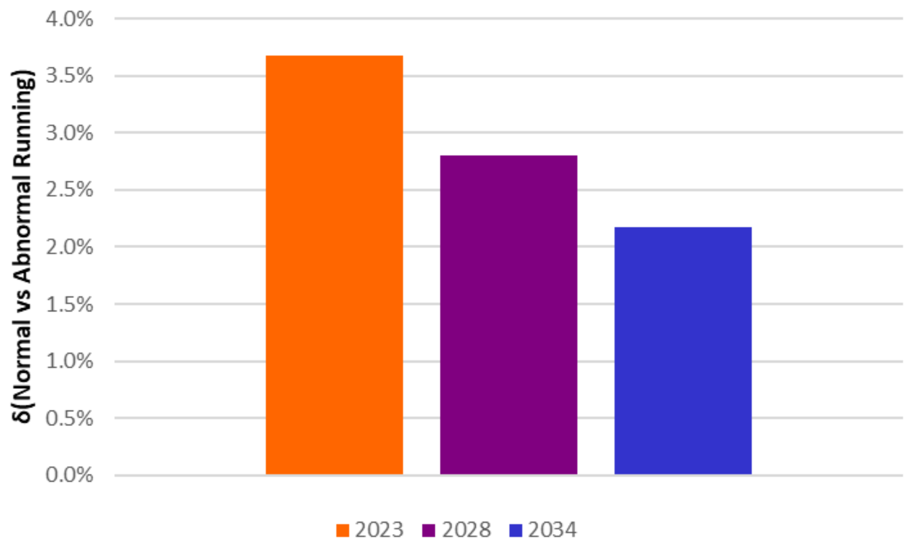


Figure 38: The difference in the volume of curtailment within the normal running model and the abnormal running model in each study year.

The impact of planned outage conditions also varies over the different seasons considered within the modelling. Within the summer months when there is already a large volume of curtailment, whilst abnormal running conditions do increase curtailment, it is only by 1% on average. It is hypothesised this is because curtailment is experienced on most days during the summer months between planned outage hours, therefore the proportional increase in curtailment is reflective of the proportion of the network that is in outage. A single network within the parametric analysis is only approximately 0.28% of the total EHV network. Therefore, the increase in curtailment over the summer months is equivalent to approximately three BSPs being in outage conditions at all times over the entire season. The IW season also experiences a similar outcome.

Our analysis shows planned outages have the largest impact within the IC season. This is because during this season under normal network conditions, generation often does not quite breach asset limits. However, when assets are derated to account for planned outages, curtailment is then required. This means that larger volumes of curtailment are experienced across the whole network during this season.

Similar to the IC season, the curtailment experienced during the winter months increases to a larger extent when planned outage conditions are considered, due to increased volumes of constraints being reached. However, the volume is lower due to a decrease in the total volume of planned outage work during the winter season.

The impact of planned outage conditions within our study is based on variance of asset ratings within a parametric model. This means that the localised nature of network outages is not being fully considered and only an average impact of derated assets is produced. Generators connected on a single network under planned outage conditions would experience much higher volumes of curtailment than assessed within our analysis. These networks would experience an increase in curtailment similar to that during the IC season. A network upon which generators experience little or no curtailment under normal conditions, will experience an increased amount of curtailment when the network is derated during planned outages. To get a more realistic view of how outage conditions impact curtailment, a local assessment using connectivity models is recommended.

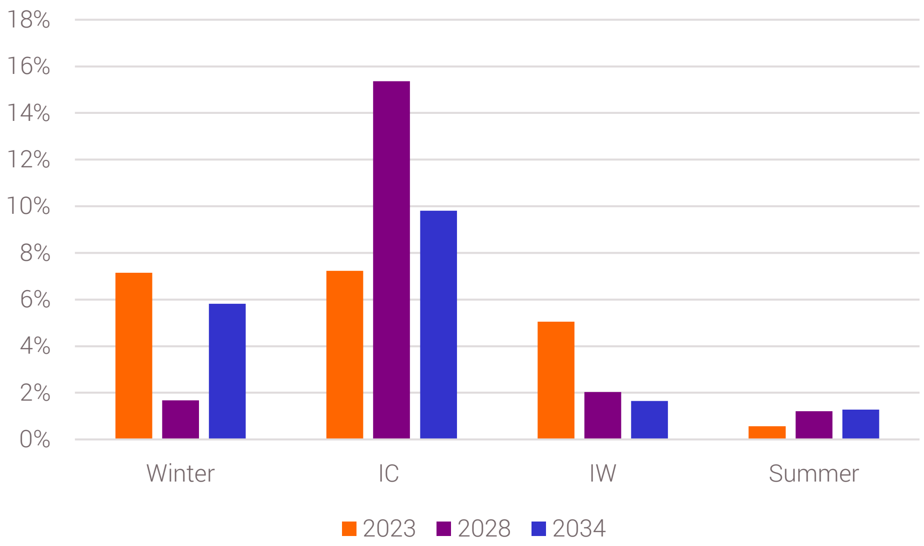


Figure 39: Seasonal comparisons of the difference in the volume of curtailment within the normal running model and the abnormal running model in each study year.

C13.	Using a parametric model gives only an average network wide view of increased curtailment due to outage conditions. Individual networks with connected generators are likely to see much larger curtailment volumes at a local level.

R8.	To gain a more realistic evaluation of the local impact of planned outages on networks with connected generation a local connectivity-based assessment should be performed.

5. Conclusions

The following conclusions can be drawn from the detailed analysis carried out in the production of this report and highlighting the learning established so far in Phase 2 of the Whole System Thinking project:

C1. By 2034, the forecast solar curtailment across the LV-132kV voltage levels is 4.8 TWh; this equates to 1.8% of the UK's total current electricity need and 1.2% of predicted electricity demand in 2034.

C2. Based on the methodology assumptions, the total calculated volume of curtailed generation on the distribution network in 2034 is 8.5 TWh, enough electricity to power 3.2 million homes for a year in the UK.

C3. Solar is expected to be the primary driver of curtailment on the distribution network with all technologies seeing an increase in curtailment volumes during daytime hours as a result. This is largely a reflection of the high forecast for installed solar capacity. At a domestic level (LV) this curtailment will be experienced as voltage rise constraints preventing domestic solar from generating freely.

C4. The new governmental policy lifting restrictions on onshore wind development may result in larger volumes of wind curtailment than forecasted in this study due to increased volumes of onshore wind generation connecting to the network.

C5. By 2034 as volumes of domestic solar increase, curtailment on the LV network surpasses that of the higher voltage levels.

C6. The EHV network experiences larger volumes of curtailment outside of the summer that LV or HV networks due to the greater mix of installed generation on the network, particularly LCTs such as wind generation and battery storage.

C7. The 132 kV network experiences higher volumes of predicted curtailment outside of the summer months than other voltage levels due to a more varied generation mix with greater volumes of wind and gas generation.

C8. Changing assumptions around BESS load impacts the volume of curtailment calculated within the three study years.

C9. The minimal proportion of installed BESS on the LV network results in negligible change to curtailment through varying the load profile.

C10. The relationship between assumed load on the network and associated demand reinforcement is impacted greatly by changing BESS load.

C11. Using a parametric model gives only an average network wide view of increased curtailment due to outage conditions. Individual networks with connected generators are likely to see much larger curtailment volumes at a local level.

6. Recommendations

Throughout the analysis of the Phase 2 curtailment results, the following recommendations have been developed for consideration:

R1. To enable the potential consumer cost benefits of changing onshore wind policies and increased wind generation, networks must consider how connection queue lengths may delay the availability of potential onshore wind capacity.

R2. Consideration into the impact of changing tap positions to increase voltage headroom and reduce curtailment on KV networks should be undertaken. This must be balanced however with the potential increase in voltage drop issues and the associated network reinforcement requirements.

R3. To better represent the extremes of the network, that may have large volumes of localised generation and thus experience greater volumes of HV and EHV curtailment, a connectivity based model specifically developed for forecasting network curtailment is needed.

R4. Development of a load flow curtailment estimator will allow for calculation of more accurate curtailment values for generators increasing customer satisfaction and enable more LCT generation connections.

R5. When reviewing the impact of battery energy storage on consumers and the network, the response of batteries to both economic signals (high whole price for electricity) and network signals (curtailment due to network overload) must be considered.

R6. A combined network and economic model to anticipate the behaviour of BESS on the network and the potential benefits or costs to consumers is needed to help direct policy behind battery storage behaviour at the grid scale.

R7. To gain a more realistic evaluation of the local impact of planned outages on networks with connected generation a local connectivity based assessment should be performed.

Appendix I

The reinforcement upgrade numbers taken from NGEDs business plan data for EHV level are shown below.

Trigger Year	Project Title	Archetype
2026	Whitwell BSP	Suburban
2026	Bourne BSP	Suburban
2027	Rhos BSP	Rural
2025	Margam BSP	Suburban
2028	Llanfyrnach	Rural
2027	Milford Haven BSP	Suburban
2025	Ashgrove	Rural
2028	Haverford West to Brawdy 33kV CCT	Rural
2026	Golden Hill to Broadfield	Urban
2027	Reinforcement - New Alverdiscott BSP	Rural
2026	Plympton BSP	Urban
2026	Weston BSP	Urban
2025	St Tudy BSP	Rural
2025	Mahe PV 33kV	Rural
2025	Exeter City - Folly Bridge 33kV ring	Urban
2027	Camborne Treswithian Transformer	Suburban
2030	Landulph BSP	Urban
2025	St Germans to Liskeard 33kV Ring	Rural
2027	Welcome Break Sedgemoor MSA, M5 J21/22,	Urban
2025	Rame BSP	Rural
2027	Severn Banks	Suburban
2025	Radstock - Evercreech Tee - Evercreech 33kV circuit	Rural
2025	Fraddon BSP	Rural
2028	Ryeford BSP	Rural

Appendix II

GSPs used within the SCT analysis and the curtailment scaling factor to align with GB:

NGED GSPs	Connection Stack Capacity (MW)	Capacity Range Assignment
Berkswell	893	750 – 1000 MW
Bishops Wood	821	750 – 1000 MW
Bushbury	424	250 – 500 MW
Bustleholme	142	< 250 MW
Chesterfield	737	500 – 750 MW
Coventry	1056	> 1000 MW
Enderby	183	< 250 MW
Fechenham	225	< 250 MW
Kitwell	124	< 250 MW
Penn	1003	> 1000 MW
Port Ham	976	750 – 1000 MW
Pyle	425	250 – 500 MW
Rassau	110	< 250 MW
Staythorpe	687	500 – 750 MW
Stoke Bardolph	58	< 250 MW
Upperboat	151	< 250 MW
Willenhall	151	< 250 MW

Appendix III

Archetypes assignment of GSPs in NGEDs region based on connected BSPs, where a 50-50 split occurs a rural bias is assumed for GSP locations.

NGED GSP	Rural BSP connected	Urban BSPs connect	Assignment
Aberthaw Power Station	33.33%	66.67%	Urban
Abham Sgp	33.33%	66.67%	Urban
Alverdiscott Sgp	100.00%	0.00%	Rural
Axminster Sgp	100.00%	0.00%	Rural
Berkswell 132Kv S Stn	33.33%	66.67%	Urban
Bicker Fen 132Kv S Stn	100.00%	0.00%	Rural
Bishops Wood 132Kv S Stn	55.56%	44.44%	Rural
Bridgwater Sgp	100.00%	0.00%	Rural
Bushbury D 132Kv	75.00%	25.00%	Rural
Bustleholm 132Kv S Stn	100.00%	0.00%	Rural
Cardiff East Grid	0.00%	100.00%	Urban
Cellarhead 132Kv	37.50%	62.50%	Urban
Chesterfield 132Kv S Stn	55.56%	44.44%	Rural
Coventry 132Kv S Stn	30.00%	70.00%	Urban
data not available	100.00%	0.00%	Rural
Drakelow 132Kv	75.00%	25.00%	Rural
East Claydon 132Kv S Stn	40.00%	60.00%	Urban
Enderby 132Kv S Stn	16.67%	83.33%	Urban
Exeter Main Sgp	80.00%	20.00%	Rural
Feckenham 66 11Kv S Stn	0.00%	100.00%	Urban
Grange	0.00%	100.00%	Urban
Grendon 132Kv S Stn	60.00%	40.00%	Rural
Indian Queens Sgp	71.43%	28.57%	Rural
Iron Acton Sgp	20.00%	80.00%	Urban
Iron Acton 132Kv S Stn	50.00%	50.00%	Rural
Ironbridge 132Kv S Stn	33.33%	66.67%	Urban
Kitwell 132Kv S Stn	12.50%	87.50%	Urban

NGED GSP	Rural BSP connected	Urban BSPs connect	Assignment
Landulph Sgp	50.00%	50.00%	Rural
Lea Marston 132Kv S Stn	33.33%	66.67%	Urban
Melksham Sgp	0.00%	100.00%	Urban
Nechells East 132Kv S Stn	50.00%	50.00%	Rural
Ocker Hill C 132Kv S Stn	100.00%	0.00%	Rural
Oldbury 132Kv	66.67%	33.33%	Rural
Pembroke Power Station	100.00%	0.00%	Rural
Penn 132Kv S Stn	33.33%	66.67%	Urban
Port Ham 132Kv S Stn	42.86%	57.14%	Urban
Pyle Grid	66.67%	33.33%	Rural
Rassau Gsp	40.00%	60.00%	Urban
Ratcliffe On Soar 132Kv S Stn	40.00%	60.00%	Urban
Rugeley 132Kv S Stn	25.00%	75.00%	Urban
Seabank Sgp	25.00%	75.00%	Urban
Shrewsbury 132Kv S Stn	100.00%	0.00%	Rural
Staythorpe C 132Kv S Stn	100.00%	0.00%	Rural
Stoke Bardolph 132Kv	0.00%	100.00%	Urban
Swansea North Grid	57.14%	42.86%	Rural
Taunton Sgp	100.00%	0.00%	Rural
Upper Boat	37.50%	62.50%	Urban
Uskmouth	25.00%	75.00%	Urban
Walpole 132Kv S Stn	100.00%	0.00%	Rural
West Burton 132Kv S Stn	25.00%	75.00%	Urban
Willenhall 132 25Kv S Stn	33.33%	66.67%	Urban
Willington 132Kv S Stn	50.00%	50.00%	Rural

Appendix IV

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

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

EHV Networks

HV Networks

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

LV Network

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

Safer, Stronger, Smarter Networks

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