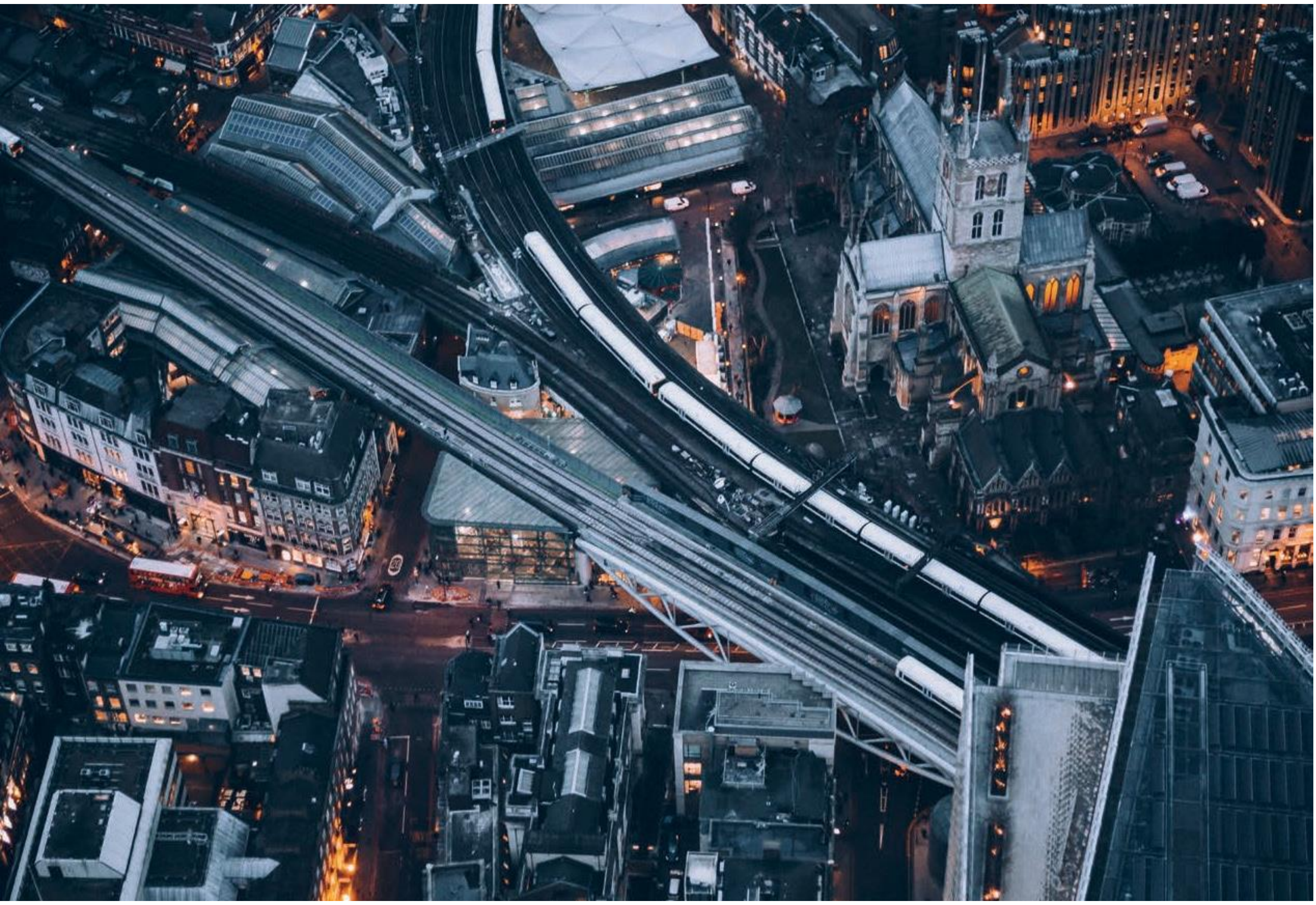

REPORT

Whole System Thinking – Phase 1 Network Modelling

Prepared for: National Grid Electricity Distribution

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Final Approval

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Executive Summary

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.

Conclusions

This project has concluded that the forecast uptake rate of distributed generation across the distribution network at the LV, HV and EHV levels will drive increases in curtailment, should network reinforcement not be carried out. This level of curtailment is forecast to grow over time, as more distributed generation is connected to the network. Based on the assumed technological uptake rates and profiles used throughout this phase of the project, and on the bottom-up methodology outlined in the report, curtailment across the distribution network due to distributed generation is expected to be primarily driven by solar generation, occurring therefore most prevalently across the middle of the day during the summer months. These conclusions are based on the assumptions detailed in this report; recommendations made throughout this report suggest approaches for improving upon assumptions made in Stage 1 of this project ahead of the subsequent Stages 2 and 3.

Next Steps

EA Technology have passed their detailed curtailment results to Baringa. Baringa are responsible for the next stage in Stage 1 of the project, where they will be conducting an economic assessment of the impact of the forecast generation on the electricity markets. Following this, a stage gate will take place where the project team will assess whether Stage 1 has suggested that there could be a whole system benefit to the GB electricity system of investment in the distribution network to release capacity. If a potential benefit is shown, the project will move into Stage 2, where the project will assess the benefit of headroom release more specifically to each of National Grid Electricity Distribution’s licence areas.

Recommendations

Throughout this study, some assumptions have been necessary and those have led to the following recommendations for National Grid to consider as part of further analysis in this space.

R1. Seek to identify peak generation profile for winter, intermediate cool and intermediate warm seasons ahead of Stages 2 and 3 of this project, to be used instead of the winter, intermediate cool and intermediate warm peak demand profiles.

R2. Should peak generation profiles for this season not be available, develop peak generation profiles for winter, intermediate cool and intermediate warm seasons.

R3. Review BESS profile assumptions ahead of Stages 2 and 3 of this project.

R4. Consider impact of BESS assumptions on connection processes.

R5. Consider whether regulatory reform is required to facilitate increase confidence in BESS impact on network operation.

R6. Consider whether analysis could be performed on the LIFO stack to develop understanding of generator types most likely to be curtailed.

R7. An analysis tool is required to better forecast curtailment requirements driven by constraints at higher voltage levels, including at the transmission level. One method of achieving this would be the development of a connectivity model across transmission and distribution levels.

Contents

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 by reducing renewable energy curtailment, facilitating more clean and cheap electricity onto the grid in place of costly gas peaker generation.

To explore this hypothesis, EA Technology have been asked to assess the likely levels of curtailed generation in the absence of investment in the distribution network. Baringa will use these outputs to make an economic and carbon impact assessment of the curtailed capacity on the electricity markets.

The project is split into three phases. The aim of the first phase of the project is to provide an assessment on the potential benefit of distribution network investment on electricity markets at a Great Britain (GB) wide level. The aim of this first project phase is to investigate the potential value in increased distribution network investment based on whole system electricity market benefits at the GB wide level. This indication will be used at a stage gate at the end of the first phase of the project to inform a decision on whether to proceed to conduct more detailed analysis during the proposed project phases 2 and 3.

This report presents the methodology EA Technology adopted to understand the likely levels of curtailment on the distribution network, detailing assumptions used throughout the modelling approach taken. It also draws several conclusions from the modelling conducted during this project phase and provides recommendations regarding how the approach could be improved ahead of phases 2 and 3 of the project.

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
NGESO	National Grid Electricity System Operator
PV	Photovoltaics
UK	United Kingdom

3. Network Modelling Methodology and Assumptions

3.1 Low Carbon Technology Uptake Rates

FES 2023 [1] provided projections of future growth in load, generation and storage technologies across GB through to 2050 in different potential scenarios. For the purposes of this project, the FES scenario “System Transformation” was selected for Stage 1 due to the close correlation of 94% average over all included technologies when compared to NGEDs Best View Scenario (which will be used in the remaining two stages of this project) and for its correlation to Baringa’s Net Zero High scenario utilised in their economic modelling during this Stage.

The Embedded Capacity Register (ECR) [2] was used to forecast the generation and storage technologies connected in 2023. Analysis was performed on the ECR to understand for each generation and storage technology, what proportion of that technology type’s peak capacity was installed on the LV, HV and EHV networks, as well as to identify the proportion of each technology type installed on rural, sub-urban and urban networks. This analysis was used to assign a proportion of each technology type’s uptake rate to LV, HV and EHV, and further apportion to the relevant archetypes in the Transform model based on whether they are rural, sub-urban or urban. It was assumed for this project that the proportion of generation and storage technologies installed on LV, HV, and EHV networks and indeed rural, sub-urban and urban network would remain unchanged over the modelled period.

The figures below show the assumed uptake rates taken from FES for LV, HV, and EHV networks respectively.

3.1.1 Solar PV Uptake Rate

Figure 1 shows the cumulative uptake rates of solar PV across GB at the EHV, HV and LV voltage levels.

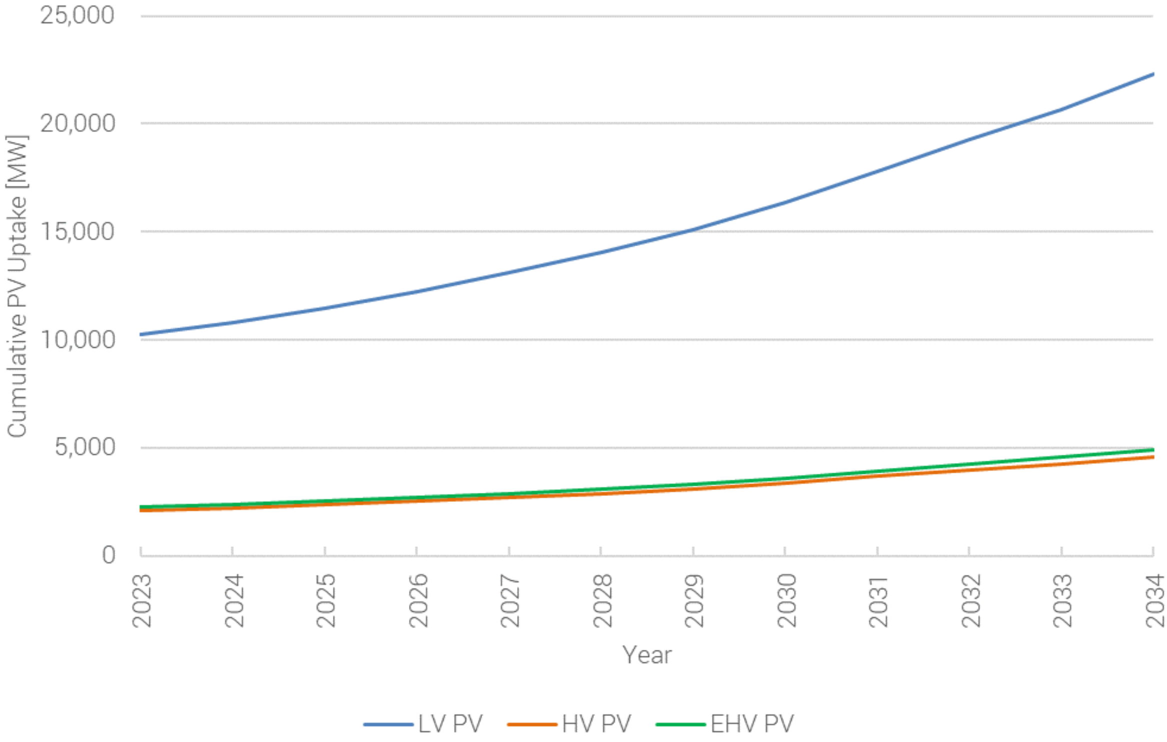

Figure 1: Cumulative Solar PV deployment across GB at the LV, HV and EHV voltage levels

3.1.2 Wind Uptake Rate

Figure 2 shows the cumulative uptake rates of wind across GB at the EHV, HV and LV voltage levels.

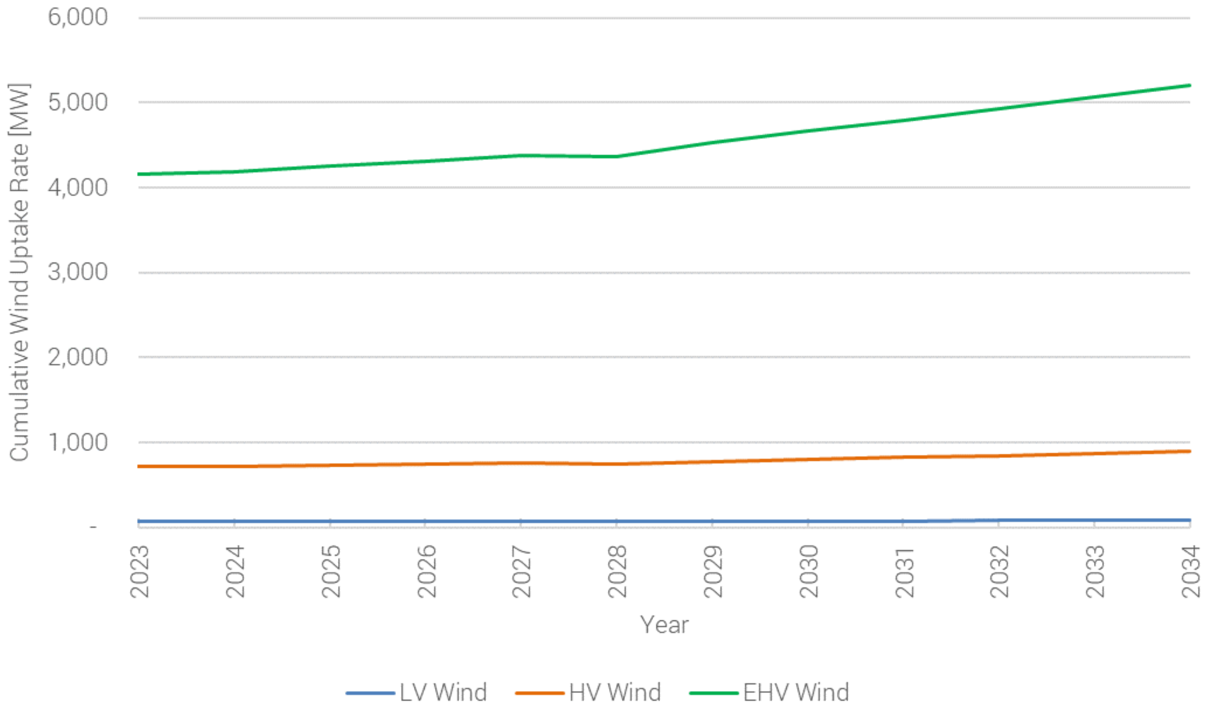

Figure 2: Cumulative Wind deployment across GB at the LV, HV and EHV voltage levels

3.1.3 Gas Uptake Rate

Figure 3 shows the cumulative uptake rates of gas across GB at the EHV, HV and LV voltage levels.

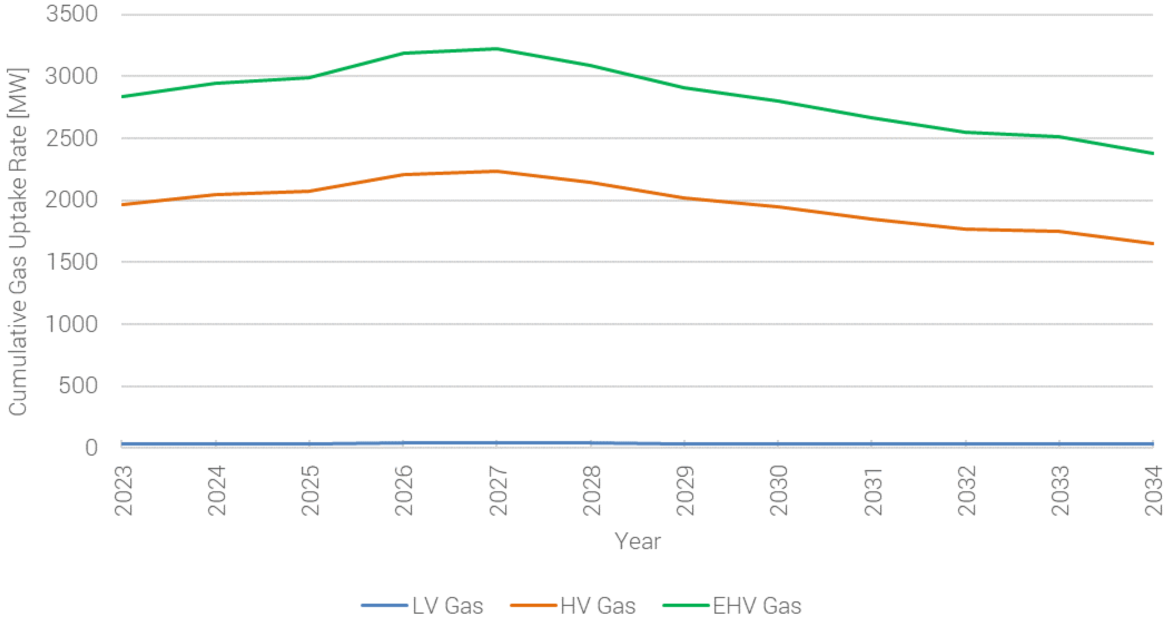

Figure 3: Cumulative Gas deployment across GB at the LV, HV and EHV voltage levels

3.1.4 Battery Energy Storage System (BESS) Uptake Rate

Figure 4 shows the cumulative uptake rates of BESS across GB at the EHV, HV and LV voltage levels.

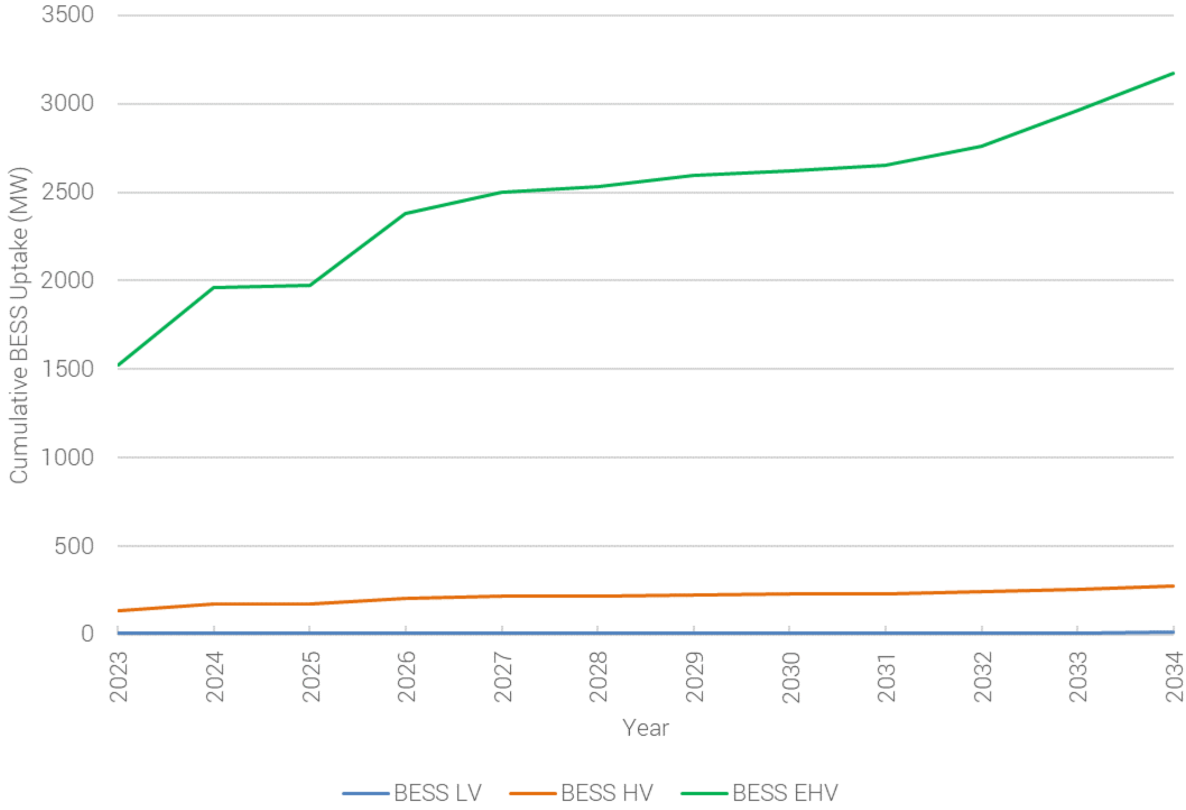

Figure 4: Cumulative BESS deployment across GB at the LV, HV and EHV voltage levels

3.1.5 Heat Pump Uptake Rate

Figure 5 shows the cumulative heat pump uptake rate across GB.

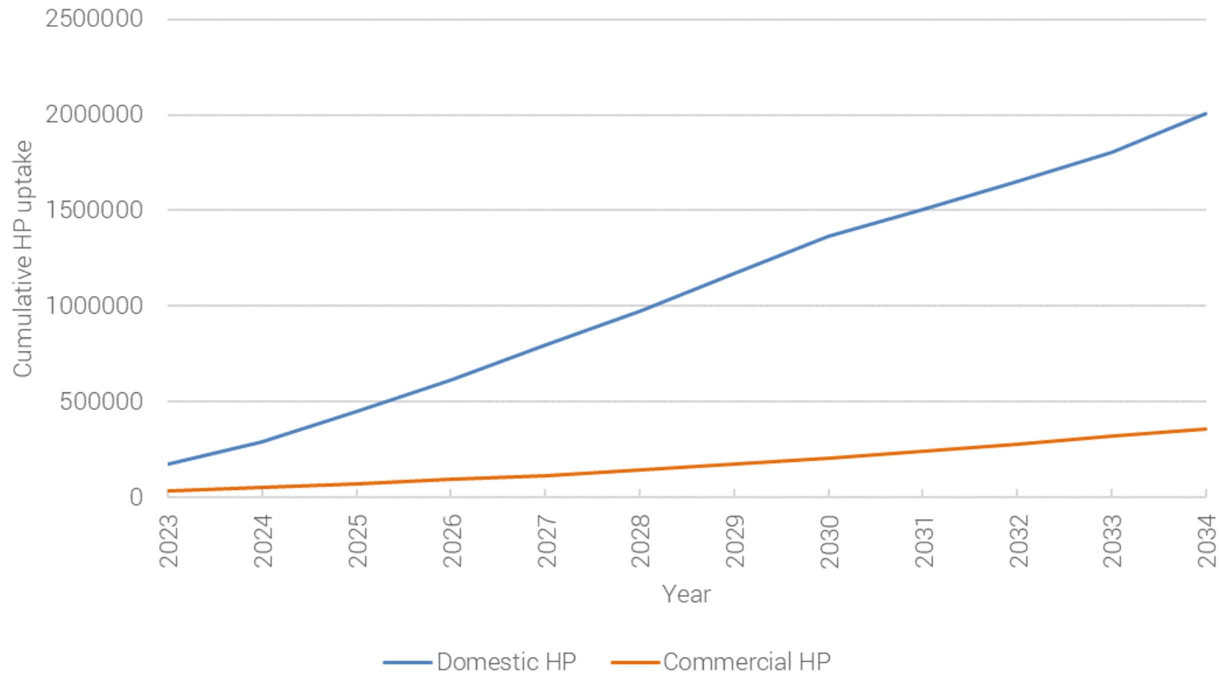

Figure 5: Cumulative Heat Pump deployment

3.1.6 EV Uptake Rate

Figure 5 shows cumulative uptake rate of residential and workplace EVCPs across GB.

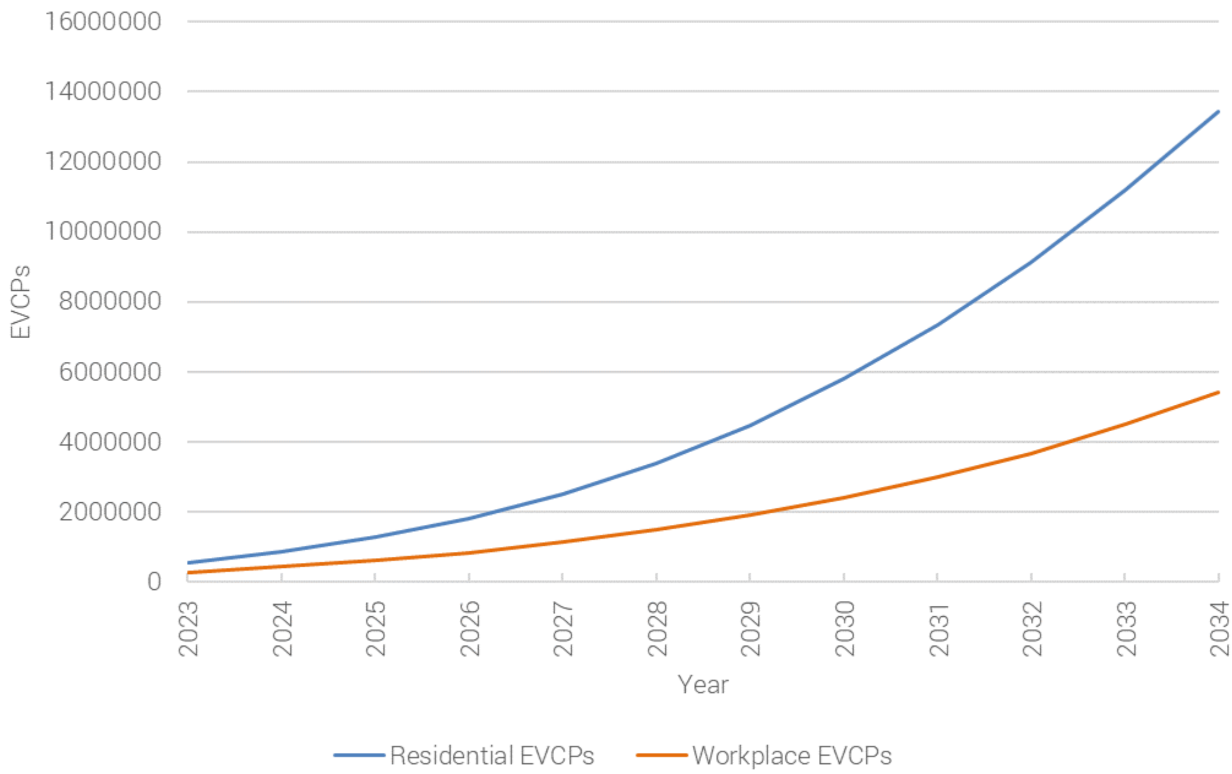

Figure 6: Cumulative EVCPs deployment

3.2 Electricity Demand, Generation and Storage Profiles

EA Technology modelled four seasonal profiles within the Transform modelling: Peak Winter Demand, Peak Summer Generation, Peak Intermediate Cool Demand, Peak Intermediate Warm Demand.

These representative profiles were chosen to align with the profiles within NGED's DFES scenarios and ensure realistic worst-case examples are captured during network planning and design. Curtailment will be witnessed to the greatest extent during periods of highest renewable generation coinciding with minimal demand on the network. These are captured in the summer season by the Summer Peak Generation profiles. However, there was no profiles available within FES / DFES for Peak Generation profiles for the winter, intermediate cool and intermediate warm periods. This is likely have led to an underestimate of expected curtailed generation during these seasons within this analysis. Shoulder modelling of transitional seasons is critical to developing a full picture of constraints throughout the year. Therefore, it is recommended that NGESO/NGED develop seasonal profiles for Peak Generation for each season, in addition to Peak Demand seasonal profiles for each season, to allow for improved curtailment estimates for the winter, intermediate cool and intermediate warm periods.

R1. Seek to identify peak generation profiles for winter, intermediate cool and intermediate warm seasons ahead of Stages 2 and 3 of this project, to be used instead of the winter, intermediate cool and intermediate warm peak demand profiles.

R2. Should peak generation profiles for this season not be available, develop peak generation profiles for winter, intermediate cool and intermediate warm seasons.

3.2.1 Solar Photovoltaic Profile

For PV, each season has a different generation profile according to assumed weather conditions, outlined as follows:

1. Summer Peak Generation: Generation by PV during a sunny, clear, summer's (June, July or August) day, representing typical peak solar generation from a UK installed PV system.
2. Winter Peak Demand: Generation by PV during an overcast cold winter's (January, February or December) day where underlying demand is at its peak.
3. Intermediate Cool Peak Demand: Generation by PV during an overcast early spring or late autumn (March, April or November) day, where underlying demand is at its peak.
4. Intermediate Warm Peak Demand: Generation by PV during an overcast late spring or early autumn (May, September or October) day, where underlying demand is at its peak.

Each PV profile shows the generation expected from a PV unit on a per kilowatt peak capacity basis. In other words, the power produced by a PV system throughout the day relative to its rated peak power output. Figure 7 shows the PV profiles from DFES 2022 for each season modelled in the Transform analysis.

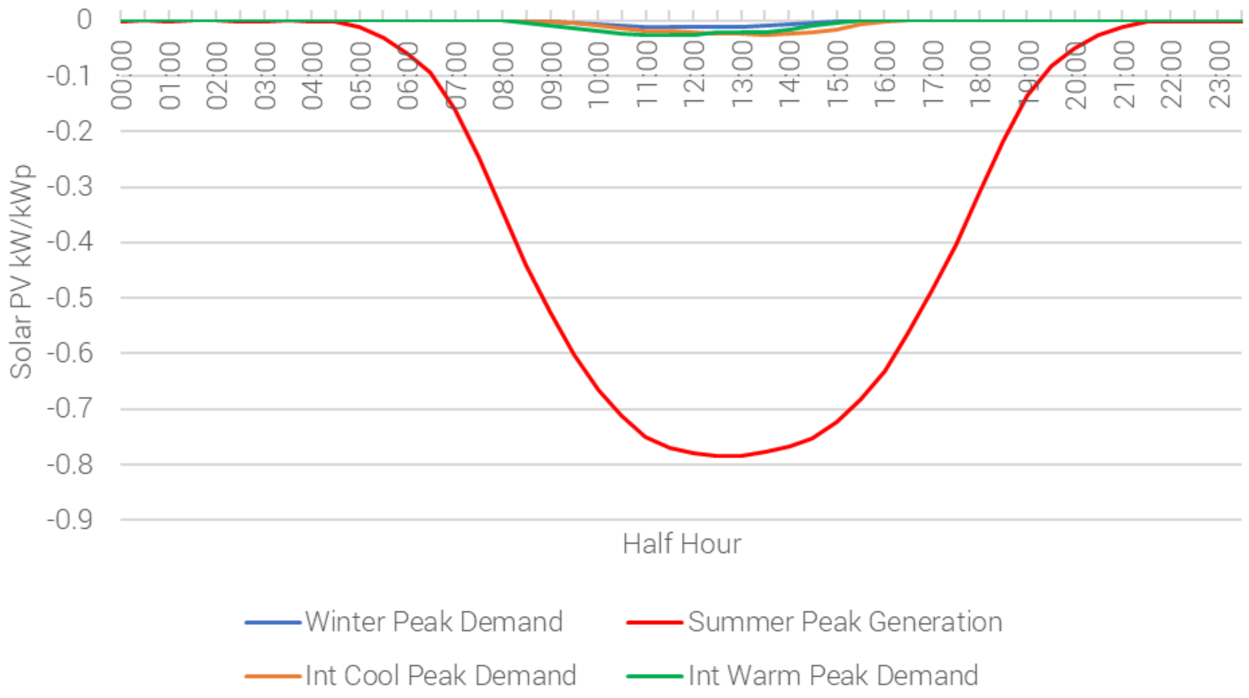

Figure 7: Solar PV profile

3.2.2 Wind Profile

For wind, each season has a different generation profile according to assumed weather conditions, outlined as follows:

1. Summer Peak Generation: Generation by wind during a blustery, clear summer's (June, July or August) day, representing typical peak wind generation from a UK installed wind turbine.
2. Winter Peak Demand: Generation by wind during an overcast still, cold winter's (January, February or December) day where underlying demand is at its peak.
3. Intermediate Cool Peak Demand: Generation by wind during a still, overcast, cold early spring or late autumn (March, April or November) day, where underlying demand is at its peak.
4. Intermediate Warm Peak Demand: Generation by wind during a still, cool, overcast late spring or early autumn (May, September or October) day, where underlying demand is at its peak.

Each wind profile shows the generation expected from a wind turbine on a per kilowatt peak capacity basis. In other words, the power produced by a wind turbine throughout the day relative to its rated peak power output. Figure 8 shows the wind profiles from DFES 2022 for each season modelled in the Transform analysis.

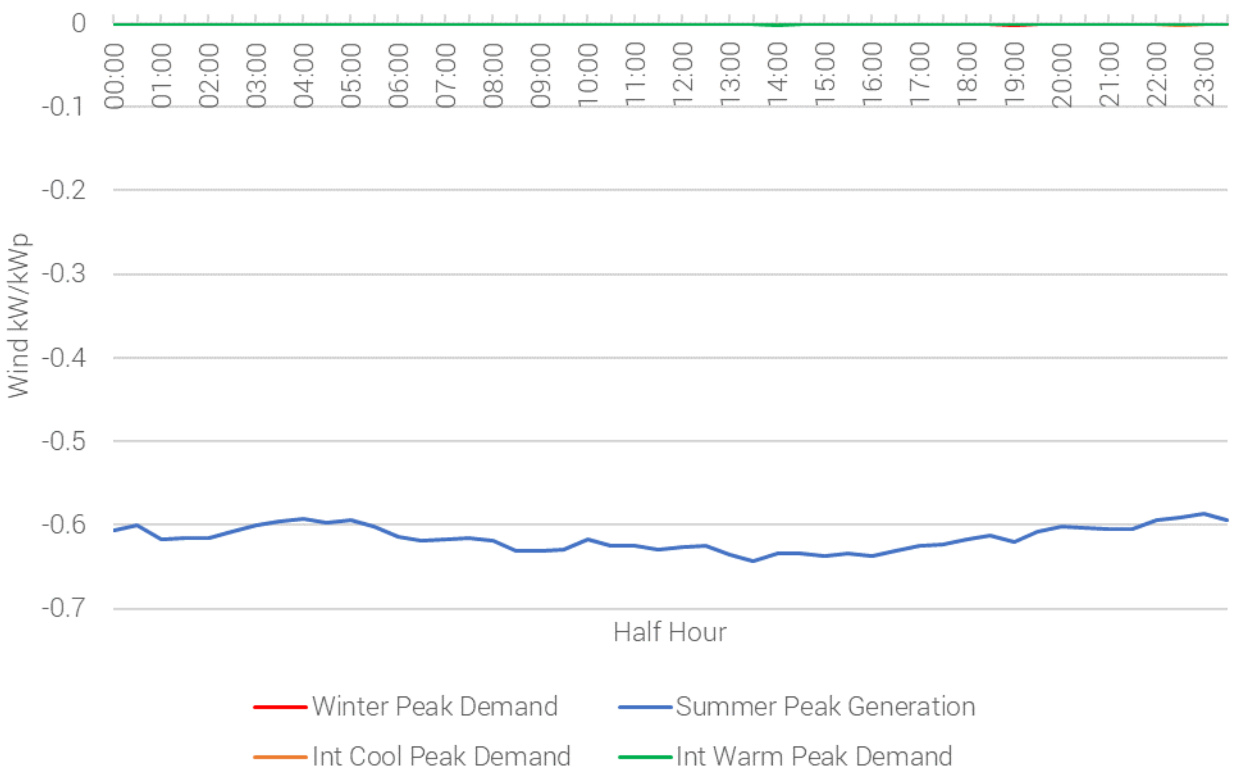

Figure 8: Wind profile

3.2.3 Gas Profile

For gas, each season has a different generation profile according to assumed weather conditions, outlined as follows:

1. Summer Peak Generation: Generation by gas during a blustery, clear summer's (June, July or August) day, representing typical peak wind generation from a UK installed wind turbine.
2. Winter Peak Demand: Generation by gas during an overcast still, cold winter's (January, February or December) day where underlying demand is at its peak.
3. Intermediate Cool Peak Demand: Generation by gas during a still, overcast, cold early spring or late autumn (March, April or November) day, where underlying demand is at its peak.
4. Intermediate Warm Peak Demand: Generation by gas during a still, cool, overcast late spring or early autumn (May, September or October) day, where underlying demand is at its peak.

Each gas profile shows the generation expected from a gas turbine on a per kilowatt peak capacity basis. In other words, the power produced by a gas turbine throughout the day relative to its rated peak power output. Figure 9 shows the gas generation profiles from Baringa's Reference Model for each season modelled in the Transform analysis. In the case of gas profiles, reference profiles were used from Baringa due to this data not being available through DFES data as with the other technologies (solar PV, wind, BESS).

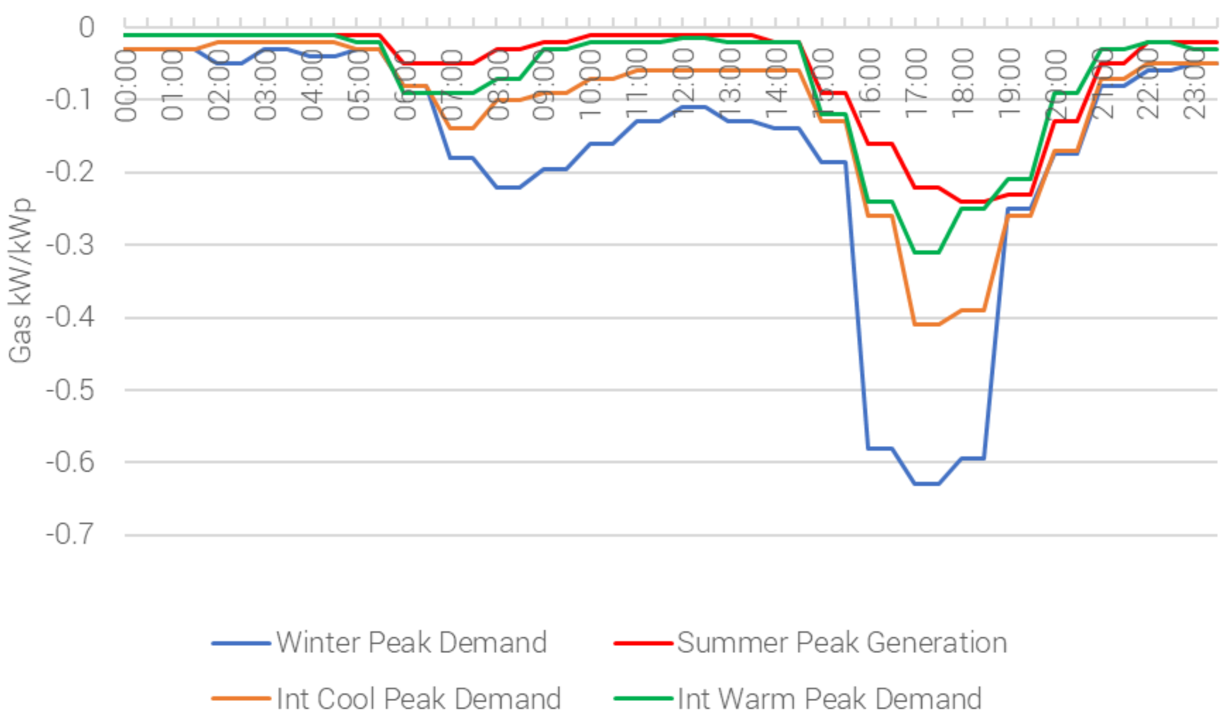

Figure 9: Gas Profile

3.2.4 BESS Profile

The process of understanding BESS profiles is in the early stages of development. For the purposes of network design, NGED utilise "worst-case" assumptions on full export during peak generation periods, and full import during peak demand periods. This ensures that the network is designed to cope with any eventuality, since BESS units have the technical capability to behave in this manner, and it is uncertain which markets they will be responding to.

For Active Network Management (ANM) calculations, network operators assume that BESS units can, and will switch between maximum import and maximum export in very short timescales, (<30 seconds). This approach is taken to prepare the network for the potential of BESS units switching to maximum export from maximum import considerably quicker than the ANM refresh rate (30 seconds). Therefore, the ANM scheme instructs ANM generators further down the LIFO stack to curtail output to ensure that network limits are not breached in the event of BESS units switching from maximum import to maximum export.

Utilising the assumption of full export during peak generation periods for the purposes of this project is likely result in over-estimation of the curtailment required. In periods of high renewable generation, electricity prices tend to be lower and BESS units are likely to be importing. Similarly, during peak demand periods, electricity tends to be more expensive and therefore BESS units are likely to respond by exporting power. This could lead to significant swings in the amount of curtailment required. For the purposes of this project phase, EA Technology have ensured that the assumption used around BESS in the modelling is aligned with NGED's standard assumption regarding the behaviour of BESS units. However, EA Technology recommend continued development of BESS unit profiles and typical behaviour, as assumptions regarding BESS behaviour have a significant impact on analysis of likely curtailment levels.

Similarly, using worst-case assumptions for modelling BESS behaviour leads to high curtailment estimates which may act as a barrier to BESS deployment, or indeed prevent connections offers being made due to the assumed potential network impact, where deployment may benefit the network by mitigating issues and enabling capacity release.

R3. Review BESS profile assumptions ahead of Stages 2 and 3 of this project.

R4. Consider impact of BESS assumptions on connection processes.

R5. Consider whether regulatory reform is required to facilitate increase confidence in BESS impact on network operation.

The BESS profile is given in kilowatt per kilowatt peak. A value of 1 for maximal discharge represents batteries discharge at their maximum rate during the season Summer Peak Generation, A value of -1 for the season Winter Peak Demand and Summer Peak Demand represent batteries charging at their maximum rate, shown in Figure 10.

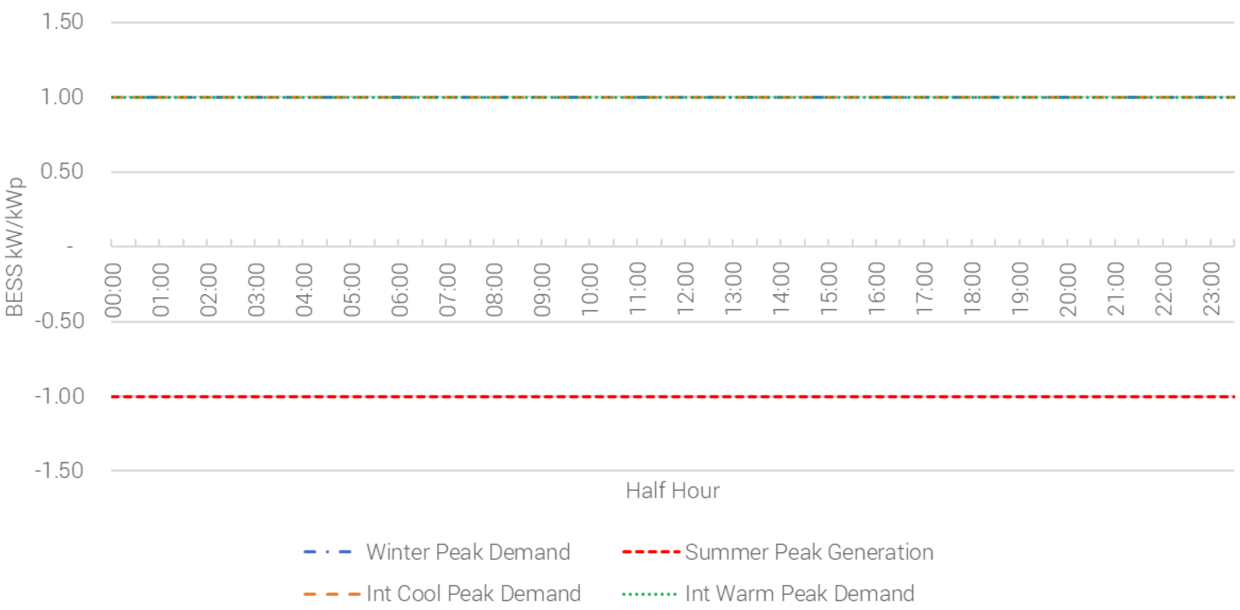

Figure 10: BESS profile

3.2.5 Heat Pump Profile

The domestic heat pump profile is shown in Figure 11. During the Summer Peak Generation season, the heat pump contributes no load, as no heating demand is required. Therefore, the heat pump does not offset any of the generation in the peak summer season for distributed generation. The Summer Peak Generation profile assumes that hot water is provided by gas heating. This assumption may require re-visiting during later phases.

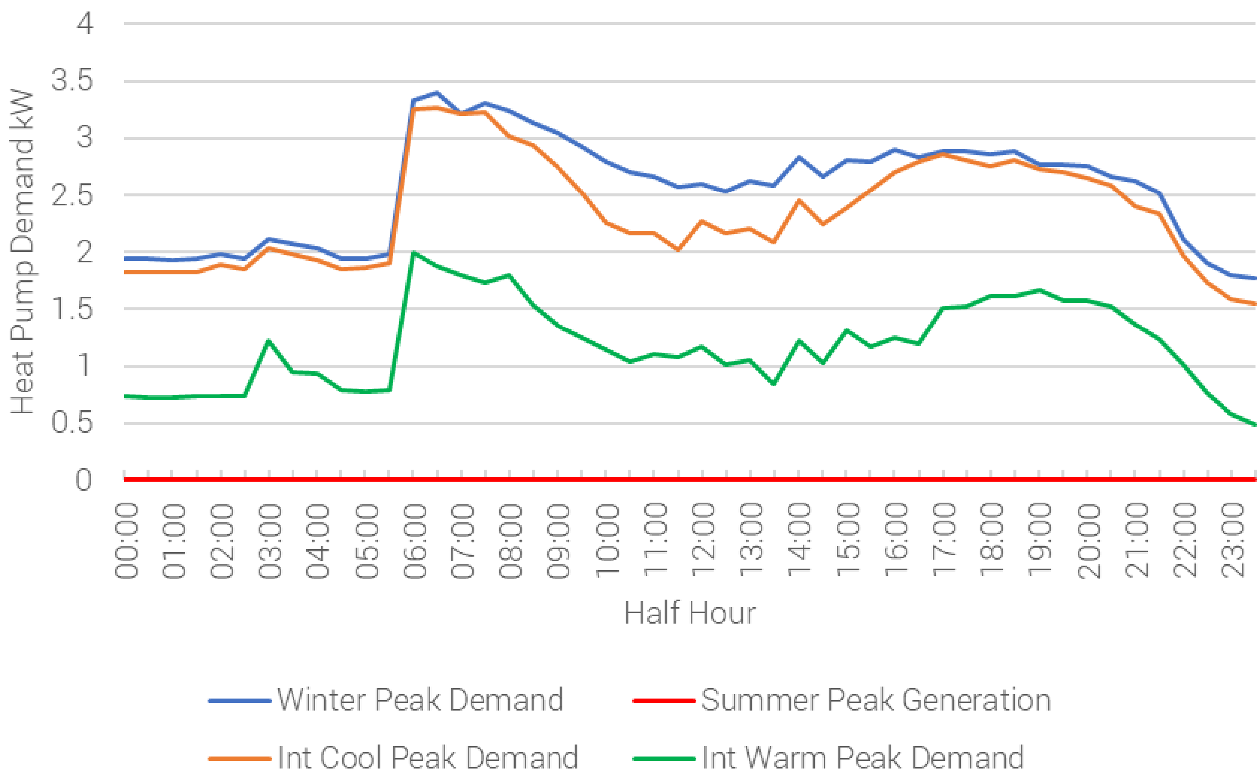

Figure 11: Domestic heat pump after diversity maximum demand (ADMD) profile

3.2.6 EVCP Profile

Figure 12 shows the assumed ADMD domestic EVCP profile. The domestic EVCP profile within DFES in identical for all seasons, reflecting consistency of charging behaviour across seasons. The demand from domestic EVCPs therefore acts to offset to some extent distributed generation during the Summer Peak Generation season, however, the effect is not as significant as it may be due to the prominence of early morning and evening charging, which is not coincident with the time of peak solar generation.

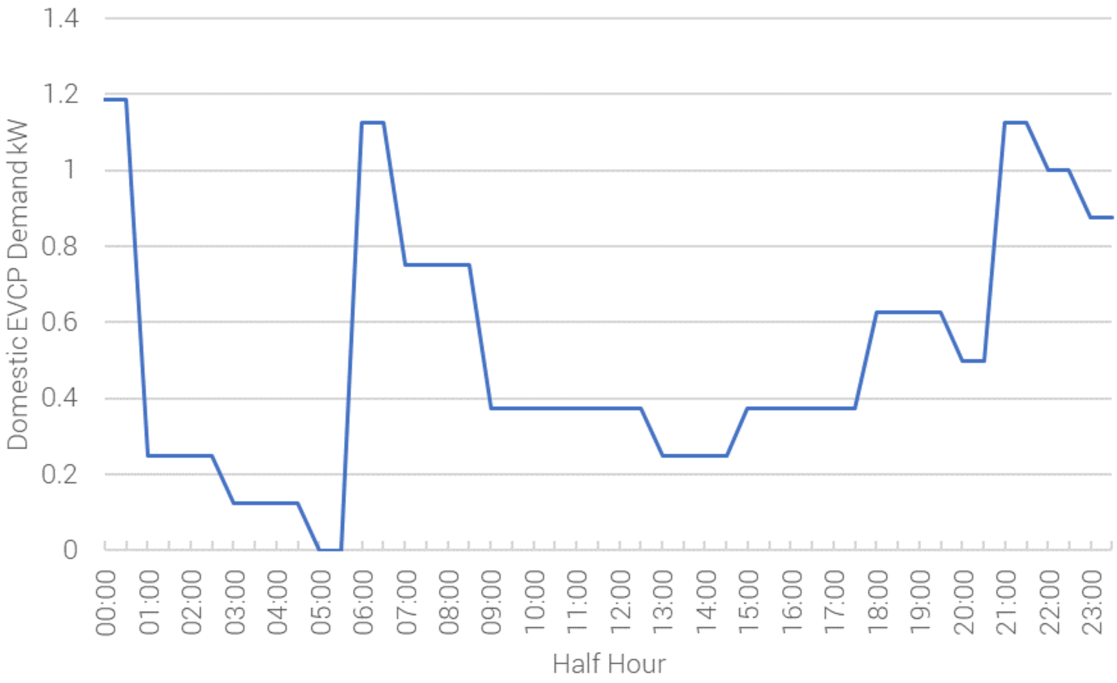

Figure 12: Domestic ADMD EVCP profile

3.2.7 Scaling from four peak days to 365 representative days

To cover a wide range of cases, NGED utilise a range of different representative days when assessing network capability. Previously, NGED have utilised the following methodology to define seasons with their Network Development Plan (based on Engineering Recommendation P27/2)[1]:

- Winter: January, February, December
- Intermediate Cool: March, April, November
- Intermediate Warm: May, September, October
- Summer: June, July, August.

Taking these months forward, the four representative peak days (Winter Peak Demand, Intermediate Cool Peak Demand, Intermediate Warm Peak Demand and Summer Peak Generation) used within the Transform modelling were translated into 365 days through generation of scaling factors to apply to the representative peak day for the remaining days within a season. The seasonal scaling factors were generated using the following methodology:

- Load data for 2022 was supplied by NGED for a series of representative archetypes at the LV, HV and EHV voltage levels.
- An average daily demand for each archetype at the differing voltage levels was calculated from this data.
- The data for the three months of each season was collated and a peak day identified, this day was assigned as 1.

All other days within this season were normalised to the identified peak day in 2022.

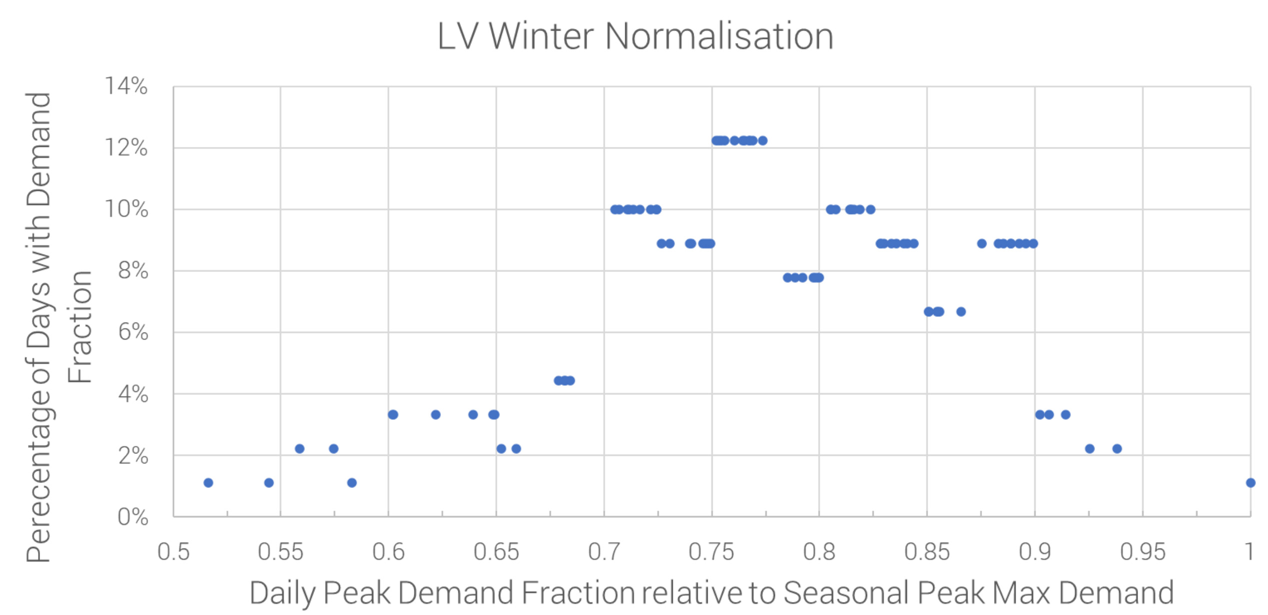

Figure 13: LV Winter Normalisation profile

The normalisation/scaling factor identified for the remaining days of the season were counted into 2.5% ranges until all days were accounted for. Resulting in the distribution plots shown below and allowed production of a series of averaged normalisation tables an example of which is given below:

[1] WPD - Network Development Plan 2022

Table 1: LV Winter Normalisation Factors

Normalisation factor	Winter (Number of days per season)
0.5	1
0.525	0
0.55	1
0.575	0
0.6	1
0.625	2
0.65	1
0.675	1
0.7	8
0.725	7
0.75	8
0.775	6
0.8	7
0.825	12
0.85	9
0.875	8
0.9	7
0.925	5
0.95	1
0.975	3
1	1

Each season could then be applied a peak day and the remainder of the days within that season scaled based on their count.

Scaling factors were designated to specific days within the year to best reflect the reference year used within Baringa's economic modelling. Baringa's reference load data was seasonally scaled, as above, and the calculated 2.5% range scaling factors applied from the peak day within Baringa's reference year down until each day had an assigned scaling factor.

The output of this process was a single scaling factor applied to each day from 1st of January to the 31st of December that correlated to the distribution of demand and generation vs the peak day across the network and to the economic load profile used by project partners Baringa.

3.3 Feeder Archetypes

Table 2: Feeder Archetypes

Number	Network Archetype Name	Description
EHV1	Urban Underground Radial	Radial underground EHV feeders supplying urban distribution primary substations.
EHV2	Urban Underground Meshed	Meshed underground EHV feeders supplying urban distribution primary substations.
EHV3	Suburban Mixed Radial	Radial mixed construction (combination of overhead and underground) EHV feeders supplying suburban primary substations.
EHV4	Suburban Mixed Meshed	Meshed mixed construction (combination of overhead and underground) EHV feeders supplying suburban primary substations.
EHV5	Rural Overhead Radial	Radial overhead construction EHV feeders supplying rural primary substations.
EHV6	Rural Mixed Radial	Radial mixed construction (combination of overhead and underground) EHV feeders supplying rural primary substations.
HV1	Urban Underground Radial	Radial Underground feeders supplying primarily urban distribution substations.
HV2	Urban Underground Meshed	Meshed Underground feeders supplying primarily urban distribution substations.
HV3	Suburban Underground Radial	Radial Suburban underground feeders supplying primarily sub-urban distribution substations.
HV4	Suburban Underground Meshed	Meshed Suburban underground feeders supplying primarily sub-urban distribution substations.
HV5	Suburban Mixed Radial	Radial Suburban feeders (mixture of underground and overhead) supplying primarily sub-urban distribution substations.
HV6	Rural Overhead Radial	Radial rural overhead feeders supplying rural distribution substations.
HV7	Rural Mixed Radial	Radial rural feeders of mixed construction (overhead and underground) supplying rural distribution substations.
LV1	Central Business District	Radial underground central business district feeders supplying only commercial customers. Typically found in town and city centres.
LV2	Dense Urban (Apartments etc.)	Radial underground feeder typical of those found in areas on dense population in cities (such as where there are many apartments in close proximity). Feeder supplies a range of residential property types.
LV3	Town Centres	Radial underground feeder typical of those found in town centres. These feeders supply primarily commercial customers but also have a small number of domestic customers.

Number	Network Archetype Name	Description
LV4	Business Park	Radial underground feeder with only commercial customers representative of a typical business park.
LV5	Retail Park	Radial underground feeder with only commercial customers representative of a typical retail park.
LV6	Suburban Street (3 4 Bed Semi-detached or Detached Houses)	Radial underground feeder representative of a typical suburban area. This feeder supplies detached and semi-detached residential properties.
LV7	New Build Housing Estate	Radial underground feeder representative of a typical new build housing estate.
LV8	Terraced Street	Radial underground feeder representative of a typical feeder supplying a row of terraced houses.
LV9	Rural Village (Overhead Construction)	Radial overhead feeder supplying mostly domestic customers, typical of that found in rural villages.
LV10	Rural Village (Underground Construction)	Radial underground feeder supplying mostly domestic customers, typical of that found in rural villages.
LV11	Rural Farmsteads Small Holdings	Radial overhead feeder typically used to supply small groups of houses or small farms.
LV12	Meshed Central Business District	Meshed underground central business district feeders supplying only commercial customers. Typically found in town and city centres.
LV13	Meshed Dense urban (apartments etc)	Meshed underground feeder typical of those found in areas on dense population in cities (such as where there are many apartments in close proximity). Feeder supplies a range of residential property types.
LV14	Meshed Town centre	Meshed underground feeder typical of those found in town centres. These feeders supply primarily commercial customers but also have a small number of domestic customers.
LV15	Meshed Business park	Meshed underground feeder with only commercial customers representative of a typical business park.
LV16	Meshed Retail park	Meshed underground feeder with only commercial customers representative of a typical retail park.
LV17	Meshed Suburban street (3 4 bed semi-detached or detached houses)	Meshed underground feeder representative of a typical suburban area. This feeder supplies detached and semi-detached residential properties.
LV18	Meshed New build housing estate	Meshed underground feeder representative of a typical new build housing estate.
LV19	Meshed Terraced street	Meshed underground feeder representative of a typical feeder supplying a row of terraced houses.

3.4 Transform Model Assumptions

The Transform Model[2] presents a parametric model of an entire electricity distribution network. This model builds on data from multiple sources, which includes:

- A range of hosting capacities from prototypical representations of different feeder categories
- A range of solutions for improving hosting capacity that a network operator may employ. (This includes network led solutions such as new transformers and non-network solutions such as tariffs or customer storage)
- Electricity consumption profiles of different customers classes
- Generation profiles of varying solar PV, battery storage and EV behaviour
- Installation rates for different DER (such as PV generation and battery storage).

As a parametric model based on representative feeders, it is not an exact replica connectivity model of Great Britain's electricity distribution network. Input variation and clustering to represent socio-economic factors is used to capture additional diversity around the network. However, a parametric model based on representative feeders is by its nature unable to capture the full diversity of feeders on the physical network for which a full connectivity model would need to be developed. Instead, a balance is needed between input parameters such that the model is representative of the entire network and able to provide outputs upon which confidence and strategic decisions can be made.

To ensure that the model is representative, various verification checks have been conducted to ensure key input and output parameters in the model are in alignment with the observed values. Specific details of model verification are included in section 3.5of this report. However, there is always a level of uncertainty around whether a different selection of representative feeders may have produced different outputs.

The Transform Model® overlays the anticipated future demand that will be placed upon the network from various low carbon technologies onto the existing network. In instances where network feeders are taken beyond acceptable network quality standards, the Transform Model® simulates the technical and economic choices that a network owner will have to make to maintain an acceptable service.

The following sections set out some of the assumptions made specifically with regards to this analysis.

3.4.1 Maximum Low Carbon Technology Deployment

To support the deployment of LCTs across the LV, HV and EHV networks in Transform, it is important to understand the maximum amount that can typically be expected to be installed at each property. It has been assumed that each property type can accommodate a maximum quantity of LCTs as detailed below

Table 3: Maximum LCT Deployment Assumptions

	Domestic	Commercial
PV (kW peak)	4	40
BESS (KW peak)	15	50
Heat Pumps (number)	1	3
EVCPs (number)	1	25

For HV and EHV networks during this phase of the project EA Technology have effectively capped the level on deployment based upon maximal connection sizes registered in the ECR today. This was done via the Clustering Methodology described in section 3.4.2.

[2] https://www.eatechnology.com/engineering-projects/the-transform-model/

3.4.2 Low Carbon Technology Clustering

In practise, it is unlikely that a completely uniform distribution of LCT uptake will occur across customers within each distribution network feeder type. Instead, there is likely to be some feeders which see a greater increase in LCTs before others due to socio-economic factors. To capture this uncertainty, Transform has a clustering feature that allows the proportion of LCTs deployed to be varied, allowing diversity in uptake rates of LCTs across any feeder type to be captured. This is achieved using 10 clustering bins. LCTs (PV, BESS, EVCPs and heat pumps) have been assumed to be deployed with variability across the clustering bins such that some clusters will see significantly higher uptake earlier than others.

The allocation of LCTs to clustering bins on the LV network used a standard clustering methodology agreed by GB DNOs. These clustering assumptions cover a full variety of feeder types from feeders with very high levels of LCT penetration to feeders with very low levels of LCT penetration. This clustering approach gives a broad overview of challenges that will occur on the distribution network, covering feeders with very high to very low numbers of LCTs deployed.

It has been assumed for the purposes of this study that the uptake rates of PV, BESS, EVCPs and heat pumps are correlated. In other words, those households most likely to deploy PV are also the most likely to deploy BESS EVCPs and heat pumps.

The clustering assumptions utilised at the varying voltages levels within this project are given in Table 4.

The clustering of HV and EHV connected generation (PV, wind and gas) was updated for this project by utilising the following methodology:

- Organising ECR data by voltage level
- For each voltage level, categorise as rural, sub-urban or urban to map across to the relevant network archetype
- For each archetype, organising the generation connected per archetype on the network from highest installed generator peak capacity to least installed generator peak capacity.
- Calculating the quantity of generation connected within each clustering bin, defined by how large the clustering bins are in terms of percentage of the network.

Voltage level clustering of technologies was determined using the percentage split determined through the ECR analysis. Primary substation assignments supplied by NGED of rural or urban were utilised to determine the archetype split at each voltage level where:

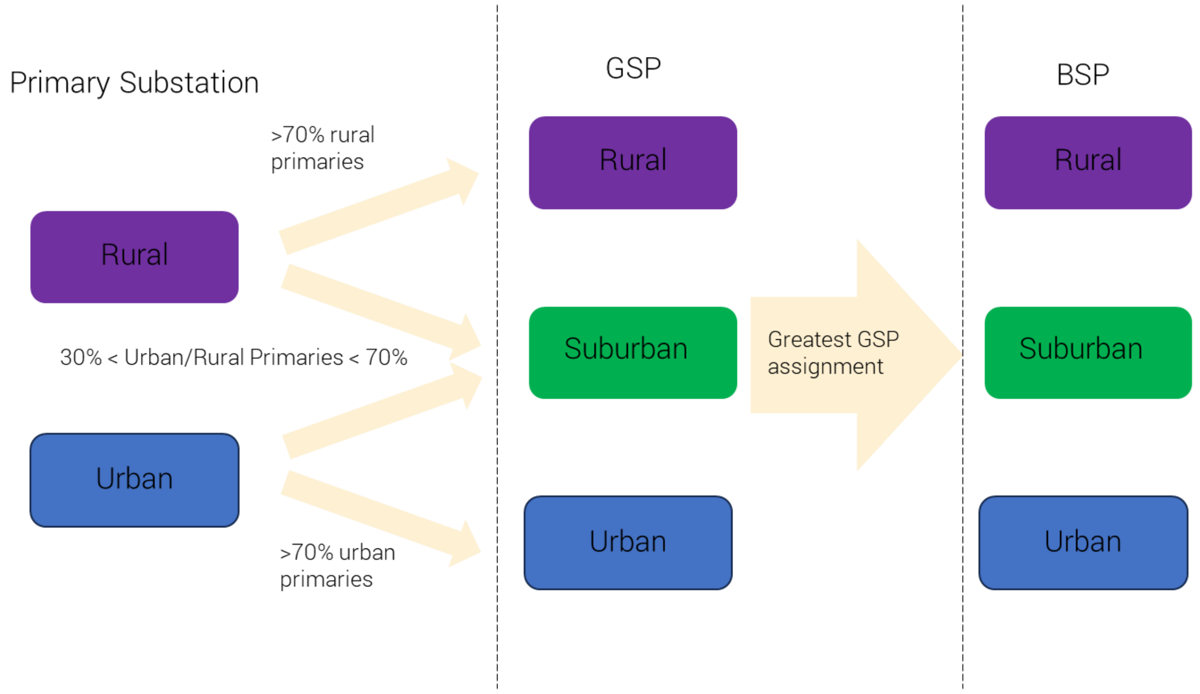

Figure 14: Archetype assignment at different voltage levels.

The same method was applied for LV substations using secondary substations voltage limits to assign archetypes to produce the suburban split within the LV level of the network model.

Once assigned an archetype connected LCTs can be assigned to each individual voltage level archetype and their percentage split determined. Table 2 highlights the different percentages of each technology per distribution voltage level.

Table 4: Clustering of generation technologies over HV and EHV archetypes.

		LCT			
		Solar	Wind	BESS	Gas
HV	Rural	37%	67%	25%	23%
	Suburban	41%	29%	30%	43%
	Urban	22%	4%	45%	34%
EHV	Rural	63%	64%	45%	19%
	Suburban	32%	29%	40%	50%
	Urban	5%	7%	15%	31%

For the LV network the clustering utilised during the SILVERSMITH [3] project was used for the individual archetypes.

3.5 Network Model Development and Validation

The Transform model developed for GB during this phase of the project was compared against three different data sets to verify it was representative of the GB wide network. The checks covered: number of LV feeders, total number of LV connected customers; and peak load observed.

As discussed previously, Transform is a parametric model that utilises representative feeders and customer data to represent an electrical network. The representative feeders and customer data must be chosen to ensure the model closely aligns with the real network. To ensure the network is representative, the number of LV feeders, the number of LV connected customers and the peak load for each licence area must all closely match their true number on the network. Exact matches across all three verification data sets are very unlikely to be achieved, since adjusting one set of input parameters will affect the others. For example, increasing the number of LV feeders in the model would lead to an increase in number of customers and an increase in peak load on the modelled network. When developing a model, compromise is required to ensure close matches to the real-world values for all these input parameters.

3.5.1 Number of LV Feeders

Table 5 compares the expected number of LV feeders in the GB network (taken from the Open LV project data [4]) to the number of LV feeders in the Transform model. The number of LV feeders is slightly higher in the Transform model than the expected figure, however being only within 5% and the expected data being approximate given the large GB wide area, it is well within tolerance.

Table 5: Comparison of LV feeder numbers in the Transform modelling against network data

Region	Expected	Model	δ (%)
GB	1,000,000	1046702	-5%

3.5.2 Total Number of LV Customers

Table 6 compares the expected number of LV customers in the GB network (taken from Ofgem data [5]) to the total number of customers in the Transform model. The model output is only slightly lower than the Ofgem approximate customer count for the GB region and well within tolerance for the Transform modelling.

Table 6: Comparison of total customer numbers in the Transform model against network data

Region	Expected	Model	δ (%)
GB	28,000,000	27,523,033	4%

3.5.3 Peak Load in 2022

Table 7 compares the peak load System Transformation load from FES active power data (supplied by ESO). The difference between peak load in the Transform model and the supplied data was only 2% showing good alignment of the model with the supplied data points.

Table 7: Comparison of the peak load in 2022 across the GB network and the output from Transform modelling

Region	Expected	Model	δ (%)
GB	58,473	59,587	-2%

3.6 Post-Transform Analysis

Once the Transform model was populated, the Transform model was run. The Transform model output used in this project was the calculated net profile for each LV, HV and EHV archetype, based upon the loads, storage and generators placed on the network, and how these were distributed across archetypes.

3.6.1 Scaling from four days to 365 days

Transform utilised profiles from four representative days, taken from DFES 2022 for the seasons Winter Peak Demand, Summer Peak Generation, Intermediate Cool Peak Demand and Intermediate Warm Peak Demand.

As described in section 3.2.7, analysis was conducted that allowed these four days to be mapped to the 365 days of the year such that the data could be fed into Baringa's 365-day economic modelling utilising the PLEXOS tool. This process allowed conversion of the four net profiles for each feeder, output from Transform to 365 net profiles for each feeder. This provided the starting point for analysis to identify the levels of constraints expected to be witnessed on each feeder archetype.

3.6.2 Constraint Types

For this project it was decided to only consider constraints caused by net export. This decision was taken for two reasons:

1. It is assumed that DNOs will be required to reinforce the network (or utilise alternative flexible management strategies) in response to demand driven constraints that occur on the network due to, for example, the adoption of EVs and heat pumps.
2. The primary whole system benefit is expected to be a reduction in utilisation of expensive gas peaker plant generated electricity due to less curtailment of cheap renewable distributed generation. Export constraints are the constraint type that effect curtailment of distributed renewable generation.

The analysis considered three types of common but distinct export constraints:

1. Voltage rise constraints occur when the voltage rise along a feeder exceeds the maximum voltage rise defined for that feeder.
2. Thermal Transformer (Generation) constraints occur when the maximum net export from a feeder exceeds the thermal capacity of the transformer associated with that feeder.
3. Thermal Cable/Conductor (Generation) constraints occur when the maximum net export to a feeder exceeds the thermal capacity of the cable or conductor as defined in Transform for that feeder.

While the constraint types are distinct, it is possible for more than one constraint type to be encountered on a feeder at the same time.

The assumption to only consider export constraints could lead to an over-estimation of the curtailment required, because it fails to consider any network upgrades that would be required to facilitate growth in demand. Many of these upgrades would also increase export capacity on the network, resulting in a lower need to curtail distributed generation.

3.6.3 Calculating Curtailment

For each feeder in the Transform model, the thermal transformer, thermal conductor and voltage rise limits are set by the user. For each half hour of the 365 net profiles for each feeder, the net export was compared to the capacity limits for that feeder. If the net export was below all the capacity limit or indeed there was a net import, the curtailment for that half hour was 0. However, if the net export was above any of the capacity limits, the curtailment was calculated as the difference between the unconstrained net export, and the smallest capacity limit of the archetype. This process was repeated for each half hour and each feeder archetype.

3.6.4 Scaling and Aggregating Curtailment

To scale the curtailment from individual feeders to the whole system, several intermediary steps were performed:

1. Scale the curtailment on individual feeders to all feeders of that archetype by multiplying through by the number of feeders of that archetype in each cluster bin to get the total curtailment across all feeders of a particular archetypes in each cluster bin, and then summing the results together to get the total curtailment across the archetypes.
2. Sum the total curtailment across the archetypes at each voltage level, to get the total curtailment at the LV, HV and EHV voltage levels.
3. Sum the total curtailment across all voltage levels to get the total curtailment across the entire LV, HV and EHV network modelled.

3.6.5 Calculating Curtailment by Technology Type

The PLEXOS modelling requires a breakdown of the curtailment witnessed by different technology types. To calculate this breakdown, EA Technology followed the below process:

1. Calculated the theoretical unconstrained generation across each voltage level for each technology type for each hour of the day, based on the FES profiles.
2. Converted this to a percentage of generation at each hour for each technology type.
3. Assumed that the curtailment, on average, is split in proportion to the proportion of generation from each technology type at each hour. In reality, the generators curtailed will be governed by the LIFO (Last In First Out) stack, but as a parametric model the assumption of proportionality at a system level is made.
4. Calculated the curtailment of each technology type according to the total curtailment and the proportion of each technology generating at the time of curtailment.

R6.	Consider whether analysis could be performed on the LIFO stack to develop understanding of generator types most likely to be curtailed.

4. Results

EA Technology's analysis allowed calculation of the curtailment across the LV, HV and EHV networks, including an indicative breakdown of which technologies were to be curtailed. This assumes that technologies are curtailed in proportion to the available generation at the time of curtailment.

EA Technology have provided the data table outputs to Baringa for use in the economic modelling that follows from the network analysis conducted by EA Technology. This section of the report provides a summary of key insights that can be drawn from the results of the network modelling conducted in this phase of the project.

4.1 Curtailment by Year

Figure 15 shows the expected average curtailment per day across the LV, HV and EHV voltage levels, as well as a total curtailment expected which is the sum of the curtailment across the LV, HV and EHV voltage levels.

The figure shows the curtailment is expected to grow over time. In later years, more distributed generation is connected to the network which drives additional need for curtailment. This is a prevalent trend especially for the LV and EHV networks. However, the HV network doesn't follow this trend, with curtailment remaining consistent across 2023, 2028 and 2034. The reason for this consistency in HV curtailment lies with the clustering assumptions (detailed in section 3.4.2), and the forecast uptake rates of distributed generation. While there is significant distributed generation installed upon the HV networks, the clustering ensures that thresholds to trigger network reinforcement are avoided as more distributed generation is installed over time.

C1.	Curtailment of distributed renewable generation across the LV, HV and EHV networks is expected to increase over time, as more distributed generation is installed.

Figure 15 shows that curtailment is primarily witnessed across the middle of the day, during times of peak solar generation. It follows as a hypothesis that solar generation is acting to drive curtailment across the distribution network; Figure 16 confirms this hypothesis.

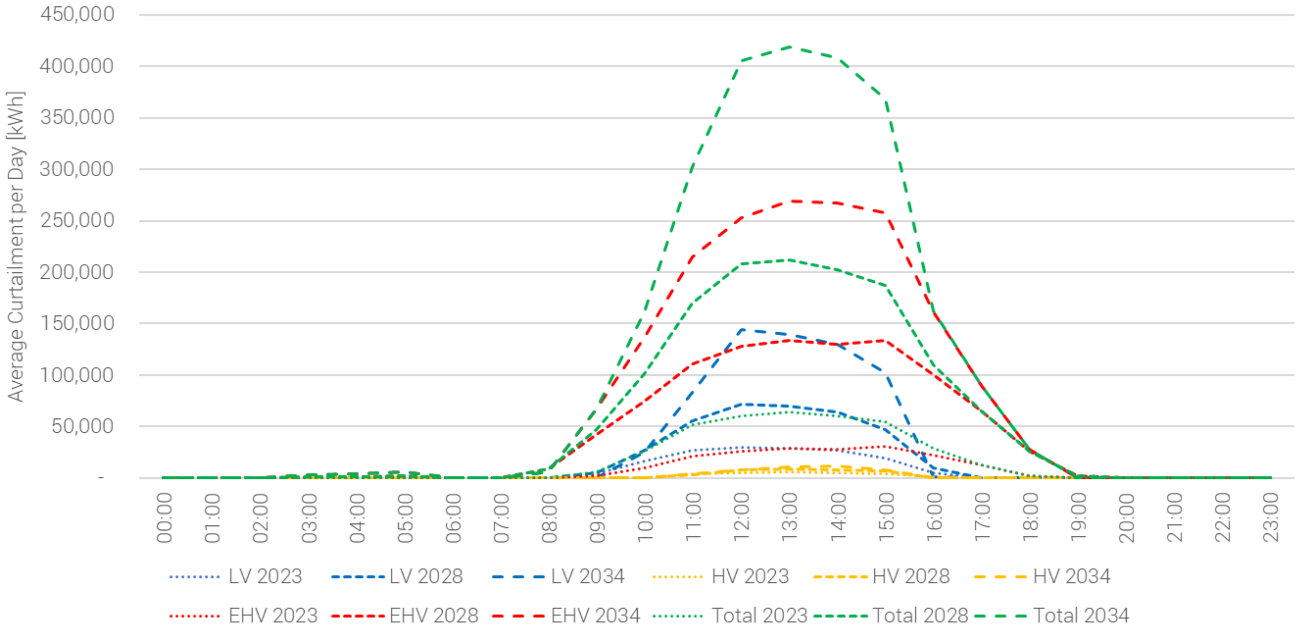

Figure 15: Average curtailment per day in the model on the LV , HV, and EHV networks in 2023, 2028 and 2034

4.2 Curtailment by Technology Type

Figure 16 shows average curtailment per day by technology type across all voltage levels for 2034. It also indicates the percentage that each technology is required to be curtailed by on average across the full year. Since it has been assumed that each technology type is equally likely to be curtailed, equal curtailment as a proportion of unconstrained generation is seen for all technology types.

The plot shows that generation peaks during the middle of the day, aligning with time of peak PV generation. It can therefore be concluded that curtailment is primarily driven the PV installed upon the distribution network. Indeed at time of peak curtailment, there is over six-fold more solar curtailed than wind or BESS.

C2. Curtailment across the distribution network is expected to be primarily driven by PV generation, under the bottom-up methodology and seasonal profile assumptions utilised throughout this project.

This might be counter to initial expectations, due to well reported increasing curtailment of wind generation across GB. However, this is a function of:

1. The scale of forecast deployment across the distribution network
2. Most wind generation and all offshore wind generation is transmission connected. Transform is a bottom-up network model only accounts for network constraints up to the EHV voltage level. Therefore any constraints at 132kV or above are not accounted for in the Transform analysis.

R7. An analysis tool is required to better forecast curtailment requirements driven by constraints at higher voltage levels, including at the transmission level. One method of achieving this would be the development of a connectivity model across transmission and distribution levels.

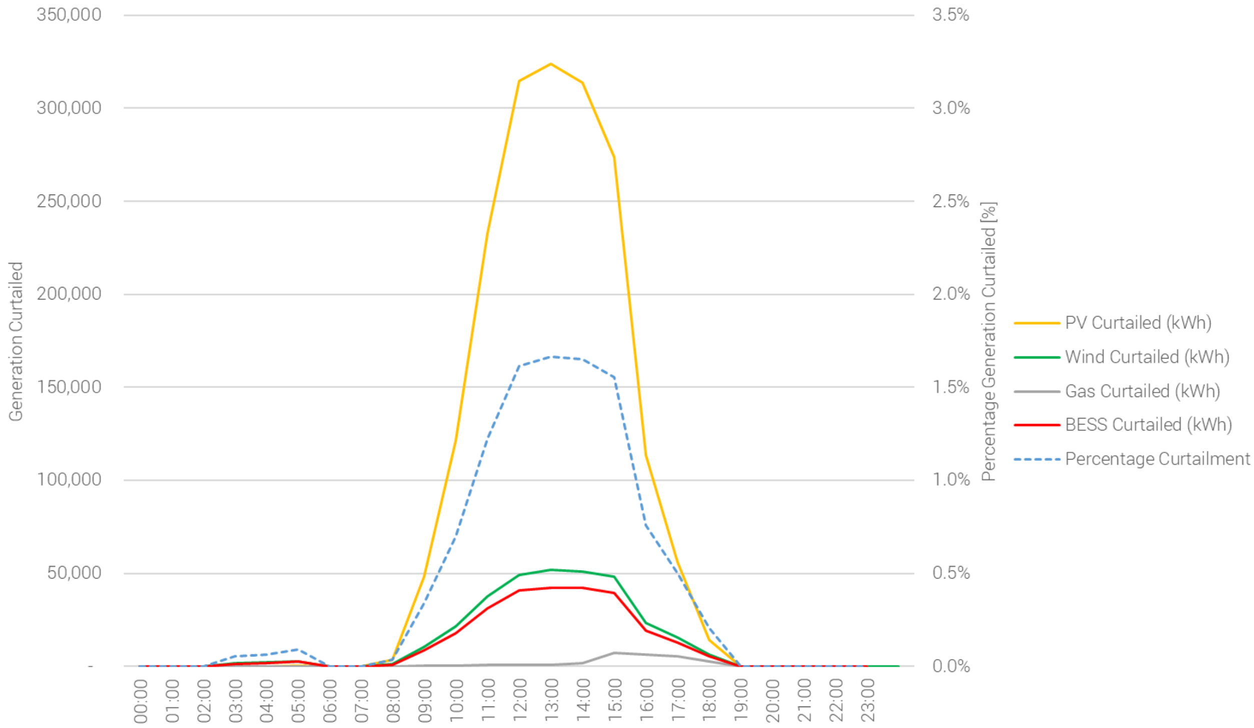

Figure 16: Average Curtailment per day (across year) by Technology Type across all voltage levels in 2034

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 this phase of the Whole System Thinking project.

C1. Curtailment of distributed renewable generation across the LV, HV and EHV networks is expected to increase over time, as more distributed generation is installed.

C2. Curtailment across the distribution network is expected to be primarily driven by PV generation, under the bottom-up methodology and seasonal profile assumptions utilised throughout this project.

6. Recommendations

Throughout this study, some assumptions have been necessary and those have led to the following recommendations for National Grid to consider as part of their further analysis in this space.

R1. Seek to identify peak generation profile for winter, intermediate cool and intermediate warm seasons ahead of phases 2 and 3 of this project, to be used instead of the winter, intermediate cool and intermediate warm peak demand profiles.

R2. Should peak generation profiles for this season not be available, develop peak generation profiles for winter, intermediate cool and intermediate warm seasons.

R3. Review BESS profile assumptions ahead of phases 2 and 3 of this project.

R4. Consider impact of BESS assumptions on connection processes.

R5. Consider whether regulatory reform is required to facilitate increase confidence in BESS impact on network operation.

R6. Consider whether analysis could be performed on the LIFO stack to develop understanding of generator types most likely to be curtailed.

R7. An analysis tool is required to better forecast curtailment requirements driven by constraints at higher voltage levels, including at the transmission level. One method of achieving this would be the development of a connectivity model across transmission and distribution levels.

7. References

[1] ESO, "Future Energy Scenarios," 2023.

[2] National Grid Electricity Distribution, "Embedded Capacity Register," [Online]. Available: https://www.nationalgrid.co.uk/our-network/embedded-capacity-register. [Accessed 08 12 2023].

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