REGEN

Bigbury Net Zero

Bigbury Net Zero feasibility report

Summary of findings from the REACH Alpha project feasibility assessment for Bigbury Net Zero.

JUNE 2025

About the Strategic Innovation Fund (SIF)

The REACH project is funded by network users and consumers under the Strategic Innovation Fund (SIF) – an Ofgem programme managed in partnership with UKRI. The lead partner is National Grid Electricity Distribution.

About Regen

Regen provides independent, evidence-led insight and advice in support of our mission to transform the UK's energy system for a net zero future. We focus on analysing the systemic challenges of decarbonising power, heat and transport. We know that a transformation of this scale will require engaging the whole of society in a just transition.

Acknowledgements

We would like to express our sincere appreciation to all those who contributed to the successful completion of this report. This work benefited greatly from the support and assistance of many individuals and organisations, including:

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- Bigbury Net Zero
- Laurence Hunter, Nicholas Jane and Mathew Pope, National Grid Electricity Distribution
- James Wale, VEPOD
- Hannah Berry, James Manson and Mathew Osborn, Passiv
- Gary Swandells, Smart Grid Consultancy

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1 The REACH project

The purpose of this report and the REACH project.

Note: This report was written specifically for the Bigbury Net Zero community to share the feasibility assessment findings from the REACH Alpha project. Sensitive information has been removed from this public version.

We are pleased to share the results of your community's REACH feasibility assessment. As one of only two communities selected for the technical evaluation, this report details the analysis conducted by our project partners to determine the suitability of the REACH energy centre solution for your local circumstances.

The REACH team conducted three assessments to evaluate whether an energy centre and smart heat controls could address potential grid constraints in your area:

- **Network assessment** - National Grid Electricity Distribution (NGED) evaluated current and projected network capacity and constraints
- **Energy centre assessment** - VEPOD conducted a detailed technical and economic analysis of energy centre viability
- **Smart heat control assessment** - Passiv analysed the potential for coordinated heat pump management to reduce peak demand.

Unfortunately, our analysis has determined that your community is not suitable for the REACH energy centre solution. While the technical assessments validated the effectiveness of the innovative REACH approach, the specific network conditions and community characteristics indicate that conventional network reinforcement would be more appropriate and feasible for addressing any future constraints.

It is important to emphasise that this study was conducted outside of NGED's Field Operations team and uses conservative demand assumptions for planning purposes. In reality, NGED's policy is to allow domestic customers to connect EVs and heat pumps freely, with notification after installation. Therefore, you should not be discouraged from proceeding with these low-carbon installations.

We sincerely thank Bigbury Net Zero for your exceptional engagement throughout this process. Your local knowledge and commitment have been instrumental in helping us understand the unique needs and opportunities within your community.

The next sections provide detailed technical reports from each partner and a summary of the key findings and analysis. The final section outlines recommendations and potential next steps for your community group. Additional information on heat decarbonisation can be found in the Appendix 3.

What is REACH?

As you know, the Rural Energy and Community Heat (REACH) project aims to support rural communities facing potential grid-constraint barriers that may delay their adoption of clean technology. This is particularly important as the number of communities facing these challenges will likely increase with the adoption of electric vehicles (EVs) and electrified heating solutions to help reach the UK's net-zero ambitions. The REACH project is funded by the Strategic Innovation Fund (SIF), an Ofgem programme administered in partnership with UK Research and Innovation (UKRI). National Grid Electricity Distribution (NGED) leads this initiative with several specialised partners, including VEPOD (a grid-free EV charging solution), Passiv (a smart thermostat company), and Regen (an evidence-led energy insight and advisory organisation).

REACH aims to engage and work with rural communities to overcome these challenges. To date, the project has worked with more than 80 communities, each bringing diverse backgrounds, experience levels, organisational capacities, technological interests and existing renewable energy assets.

Your community organisation has been an important contributor to this process. Our engagement began with a structured 'Discovery' phase where we collected expressions of interest from 82 communities, hosted workshops attended by 73 community stakeholders, and received 32 detailed questionnaire responses. This was followed by the 'Alpha' phase, where seven promising communities, including yours, participated in comprehensive 90-minute interviews to assess suitability for further technical studies. Following this evaluation, two communities were selected to proceed to site evaluation and technical assessment, of which you were one. We have since visited your community and learnt much more about the local area. The project partners have completed their feasibility assessment, and the next section of this report summarises those findings.

2 Network assessment

A summary of National Grid's assessment of possible future network constraints in the BNZ community.

Introduction and summary of findings

Models were used for the local high voltage network to ascertain the impacts of the increased uptake of low carbon technologies (LCTs) for the Bigbury Net Zero (BNZ) communities. The models were updated using the highest demand load profiles for NGED's network that fed the BNZ communities. These load profiles (i.e., demand profiles) were then adapted and remodelled to show unabated yearly forecasted load growth until 2030, allowing increased demand at the BNZ communities.

Analysis was then completed to ensure the network met the minimum security of supply as per the requirements of the ENA Engineering Recommendation P2 for distribution network operators. This analysis allowed us to identify locations where the increased load would cause equipment to exceed its thermal ratings or voltage to fall outside acceptable limits (upper and lower). This work was completed with NGED's network in normal running conditions, with no active network faults. The analysis was then repeated for abnormal fault conditions (a P2 requirement), where demand is rerouted through different sections of the network to confirm it still operates within acceptable limits (see Figure 1 for an Explanation of Abnormal Running Fault Conditions).

The analysis identified that the constraints are within acceptable limits under normal operation. Only in the first fault conditions was it found that Feeder 520137/0782 was always outside NGED's acceptable limits. Since there is no spare headroom to charge the energy centre's integrated battery storage, it would rely solely on a generator set. With the added carbon emissions and practicality of refilling the fuel tanks, an energy centre in this scenario would not likely be the right approach.

Additionally, while the Feeder exceeded its constraints in this theoretical scenario, completing the necessary reinforcement works in time would be feasible. Therefore, an energy centre would not be required in this scenario. In the meantime, if the identified theoretical voltages materialised, NGED would likely deploy one or more mobile generator units in strategic locations to alleviate any theoretical voltage constraint.

The voltage limit constrained in Feeder 340040/0017, found only in abnormal running conditions, was then used as a test case. Firstly, to prove the energy centre concept, VEPOD used the Feeder loading data to create new import/export demand profiles for the energy centre. The energy centre demand profiles were added to the model, finding that the energy centre could remove the voltage constraint for Feeder 340040/0017. The solution involved a non-linear relationship that increased voltage above the minimum limits required.

Second, the community heat pump demand was removed from the baseline to the 2030 unabated load profiles. Passiv then completed modelling of heat pump controls to reduce the community heat pump demand during high Feeder demand. It was found to have a limited impact on the Feeder demand profile due to the relatively small community size compared to the Feeder customer numbers.

Scenarios

To determine the headroom for each community, the Secondary System Planning Team (National Grid DSO) undertook an edge case analysis of the affected high-voltage circuits for both intact and abnormal running fault conditions to comply with the above-mentioned ENA Engineering Recommendations P2.

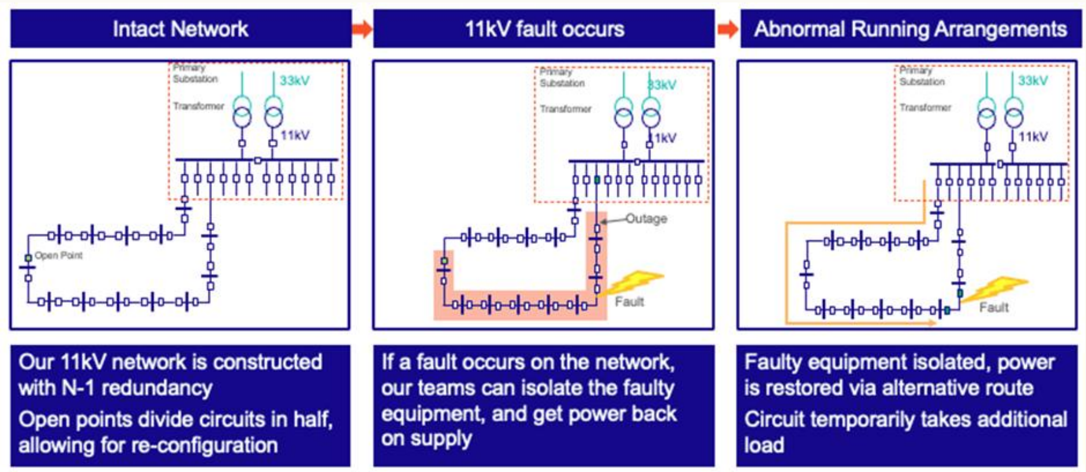


Figure 1: Explanation of abnormal running fault conditions

Load profiles

Baseline load profiles for each Feeder (a section of the network) were created, using the highest recorded demand for each half hour for a 24-hour period and adding any demand masked by generators (e.g., wind turbines, solar PV, etc.). This process created a baseline profile for each Feeder on a theoretical maximum demand day.

Forecasted load growth

Annual forecasted load growth profiles were created by scaling the baseline profiles to enable modelling of annual demand until 2030. All distribution substations outside the community (non-community loads) on the network were scaled using NGED's DFES 2023 Best View scenario[1] to represent realistic load growth.

As the communities have an increased ambition to decarbonise via the installation of heat pumps and electric vehicle charge points, loads were scaled using the more ambitious DFES 2024 Electric Engagement scenario at two-year intervals. An example of this projected load growth is shown in Figure 2, and a breakdown of DFES years utilised to scale the profiles is shown in Table 1. These profiles were classed as unabated as Passiv's heat pump demand controls were not yet introduced.

[1] Since countless possible combinations of factors might influence the network, the DFES focuses on four main scenarios that capture different potential futures. Regen produces the DFES for NGED's regions, and NGED creates an additional 'Best View' scenario through further engagement with local stakeholders from NGED's Distribution System Operator (DSO) team. The Best View data represents NGED's 'best guess' projection based on current trends and policies, whereas the Electric Engagement scenario assumes a higher uptake in low-carbon technologies (See the NGED DFES map for more information).

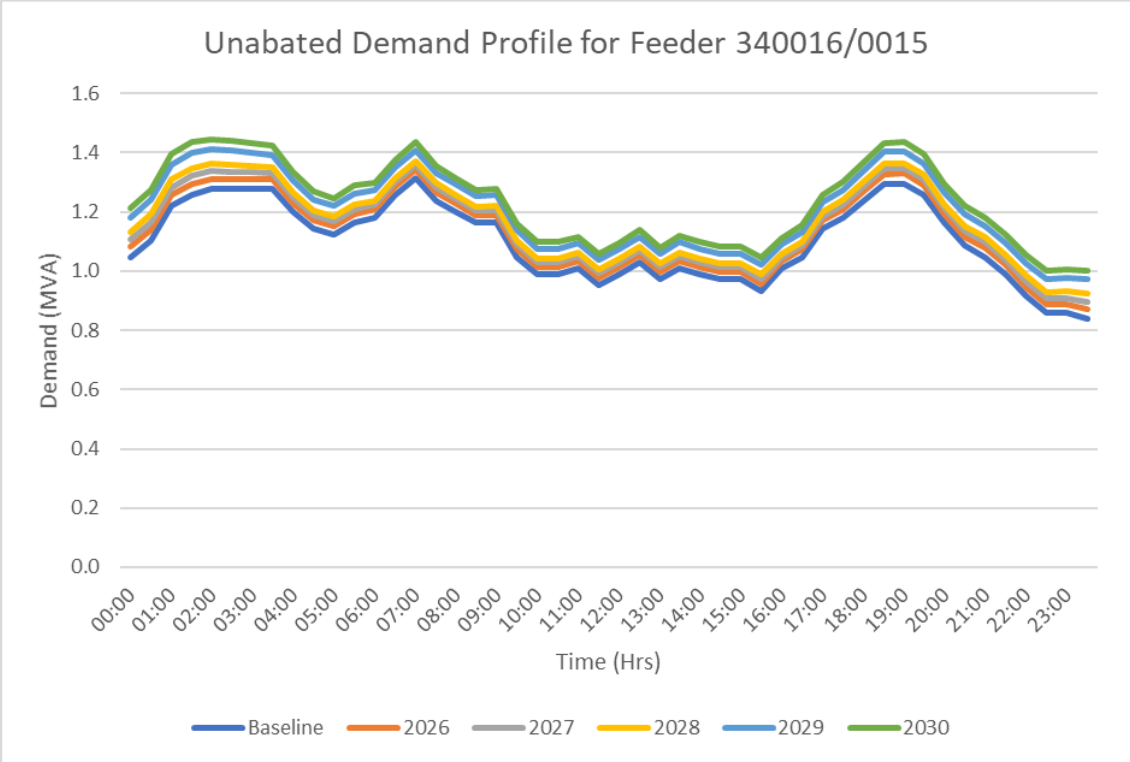


Figure 2: Example of forecasted load growth modelled on Feeder 340016/0015

Table 1. Scaling and DFES used to create forecasted load profiles

Year	Study	Scaling year used for community load (DFES 2024 Electric Engagement scenario)	Scaling year used for non-community load (DFES 2023 Best View)
Baseline	Baseline	-	-
2026	Unabated	2027	2026
2027		2029	2027
2028		2031	2028
2029		2033	2029
2030		2035	2030

Analysis

All feeders, except Feeder 340040/0017 (see Abnormal running conditions) were found to be within Feeder limits in normal and abnormal operation. Any remedial works on the network that was less than 200m were discounted from the results due to the cost and simplicity of such a solution and the relative speed at which this could be delivered.

Analysis was completed in normal and fault conditions for each load profile detailed in Table 1, identifying if and when the normal and abnormal demand exceeds the feeders' capability, creating a constraint.

If the Feeder demand was lower than its respective limits, additional demand was added to the model at the electrically worst-served community distribution substation until thermal or voltage limits were reached.

Normal running conditions

For the BNZ community, it was found that Feeder 340040/0017 was within constraints in normal operation, as shown in Figure 3.

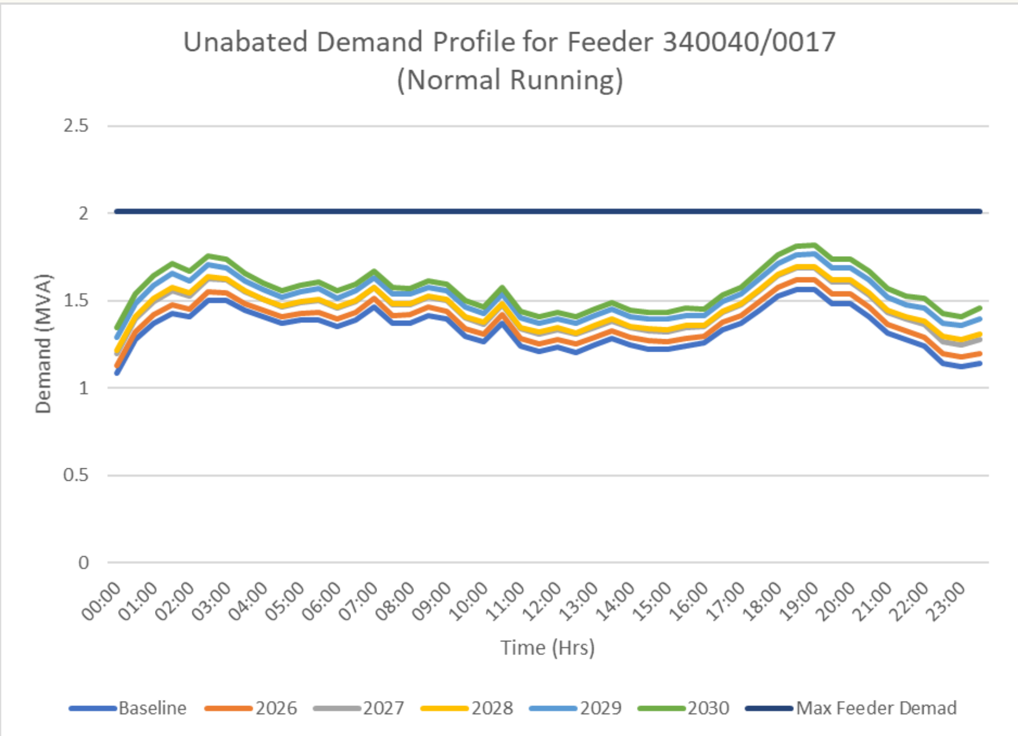


Figure 3: Normal running unabated demand profile for Feeder 340040/0017 vs maximum Feeder demand

Abnormal running conditions

The most onerous fault condition for Feeder 340040/0017 was found to be a whole circuit outage with a fault around pole 34KA3, removing any back feed from Feeder 340040/0016 or the primary circuit breaker. In this scenario, the only Feeder available to back-feed the network was from Feeder 340016/0015.

Due to voltage constraints, Figure 4 shows that the Feeder demand always exceeds the maximum feeder capacity by 62% above the maximum Feeder demand. This suggests that Feeder 340040/0017 cannot be fully back-fed under first circuit outage conditions at any time of a theoretical 'worst case' day.

As the constraint on this Feeder was voltage threshold exceedance, the Feeder capacity was found to vary over time due to the load profile at each distribution substation increasing and decreasing at different times of day relative to each other. Therefore, a point in time was selected to represent the worst-case capacity to enable further analysis and insights from the results.

As the network limits were shown to be always exceeded in this scenario, the energy centre would rely solely on a generator set to charge the integrated battery storage. With the added carbon emissions and practicality of refilling the fuel tanks, it would be unlikely that an energy centre would be viable to support this Feeder.

If the identified theoretical voltages materialised, NGED would likely deploy one or more mobile generator units in strategic locations to alleviate any theoretical voltage constraint.

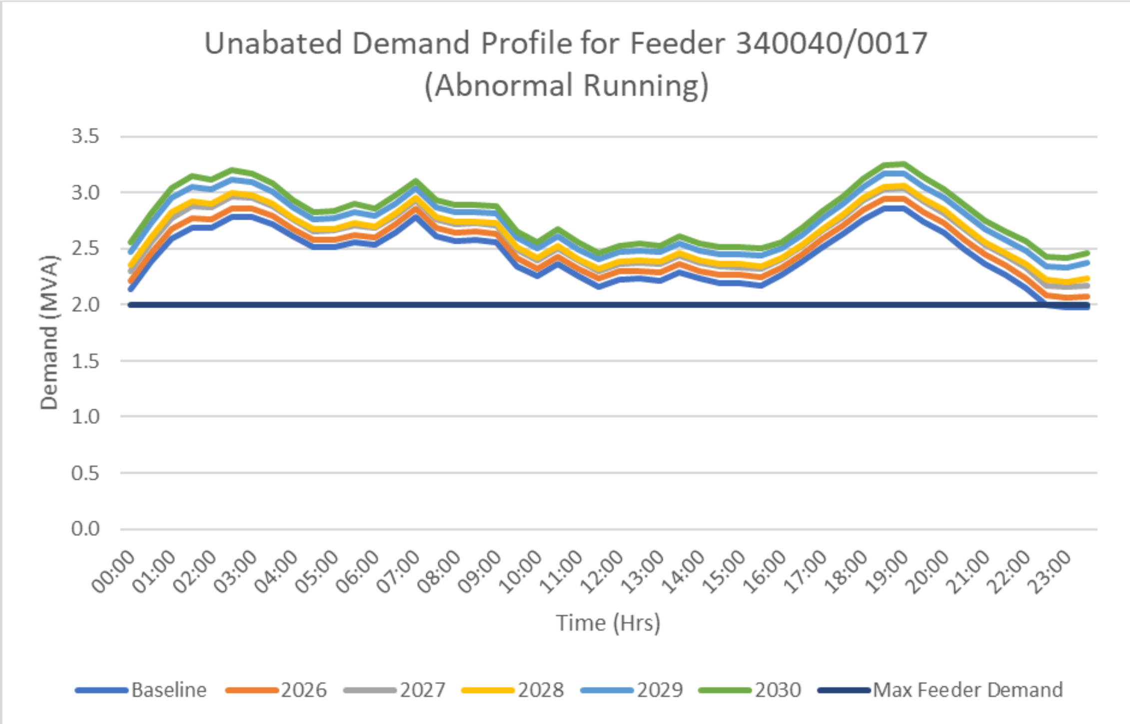


Figure 4: Abnormal running unabated demand profiles for Feeder 340040/0017, back-fed via 340016/0015 vs maximum Feeder demand

Energy centre location

While installing an energy centre for the constraints identified in your community would not likely be feasible, this analysis was required as part of the innovation project to analyse whether the energy centre can remove constraints from the network.

Therefore, based on the theoretical constraints on Feeder 340040/0017, VEPOD assessed the half-hourly load profile against the maximum Feeder demand. A single 'worst case' day (in 2030) energy centre load profile was created. This enabled analysis to confirm if the generator set was adequate to charge the battery enough to reduce the peaks of the network demand below the Feeder limit when required.

VEPODs analysis showed that there were two potential sites for an energy centre that had the potential to resolve the network's voltage constraints. The solution depends on the energy centre location and varying distribution substation demand levels at each half hour of the time series analysis, creating a complex rather than linear relationship between energy centre export and network voltage.

Passiv co-ordinated heat pump controls

For the abnormal running of Feeder 340040/0017, being back-fed from 340016/0015, the community heat pump uptake demand was subtracted from the unabated half-hourly demand profiles (baseline to 2030).

Passiv then modelled controlling the community heat pump demand to reduce the Feeder demand peaks while maintaining heating and hot water temperatures to a comfortable level.

This proved that the overall peak demand of the Feeder could be reduced with central heat pump controls in Figure 5Figure 5 and Figure 6.

If the community are willing to have coordinated heat pump controls installed, it would reduce the peak Feeder demand by 6.2%, reducing the maximum Feeder exceedance from 62.3% to 56.1%. As the community size is relatively small compared to the number of customers on the Feeder , the impact on the Feeder demand of coordinated heat pump controls is limited. This slight reduction won't impact the required network reinforcements and will have a limited effect on an energy centre (if installed on the network).

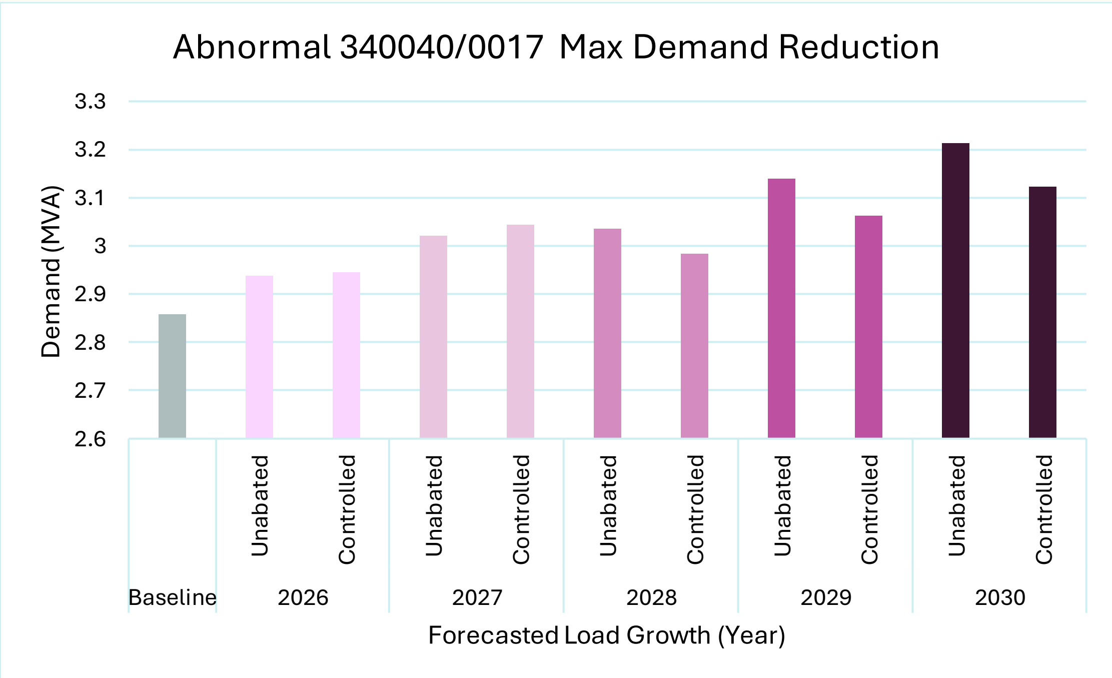


Figure 5 Reduction of total feeder demand with Passiv's coordinated heat pump controls back-feed from 340016/0015

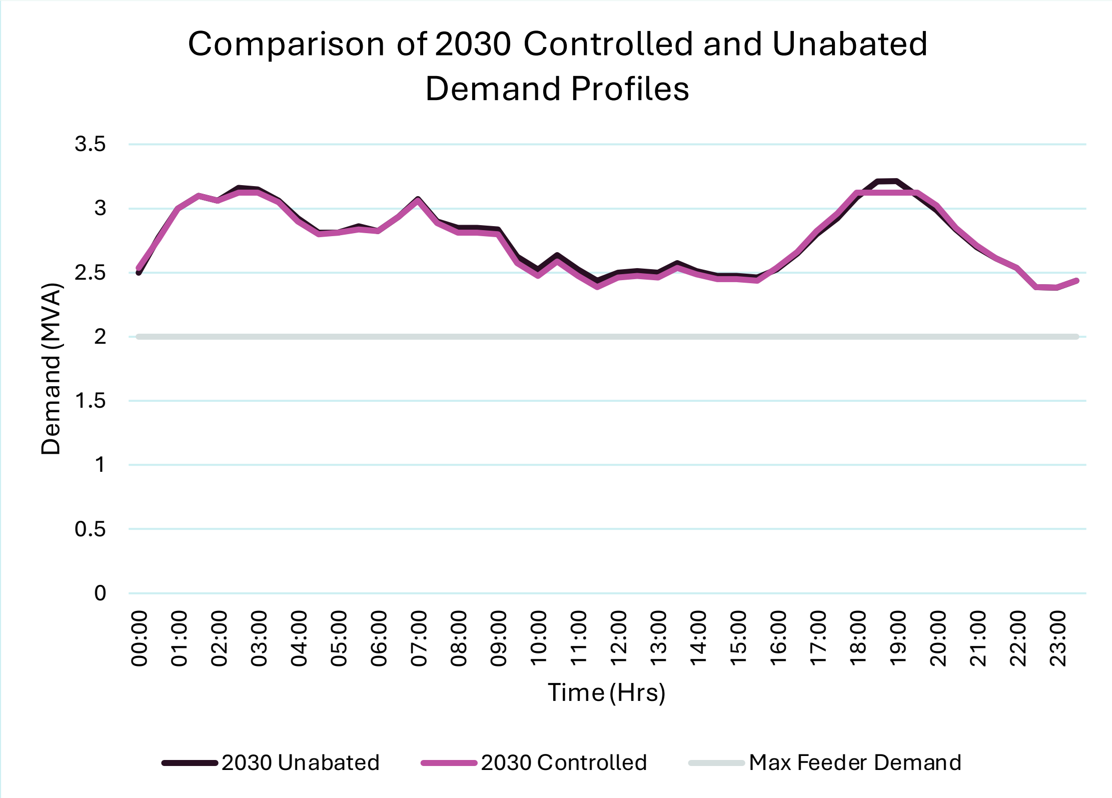


Figure 6 Comparison of 2030 coordinated heat pump controls and unabated demand profiles for back-feed from 340040/0017

3 Energy centre assessment

A summary of VEPOD's site assessment for an energy centre in the community.

Introduction

One key objective of the REACH project is to determine an energy centre's viability to reduce the Feeder demand in rural communities where Low Carbon Technologies (LCTs) are adopted at much faster rates than the standard DFES 2024 data suggest (See the NGED DFES map for more information on DFES). This document explains the methodology adopted and the results obtained for the sizing of a REACH energy centre for two selected communities as part of the Alpha phase of the REACH project.

See Appendix 1 for information on the REACH energy centre and its components. See Appendix 2 for information on the amount of fuel which would be required for the sizing of the energy centre.

Step one: forecast demand and operational scenarios

The first step of the analysis involved selecting appropriate forecast demand for corresponding 11 kV Feeder lines that serve the communities. NGED secondary system planning network engineers provided VEPOD with half-hourly forecast demand data and a figure for the maximum Feeder capacity (in MVA).

Several alternative forecast datasets were also provided. These can be summarised as follows for each Feeder:

1. Normal operation of the Feeder with no coordinated heat pump management
2. Normal operation of the Feeder with coordinated heat pump management
3. Abnormal operation of the Feeder (N-1) condition where the Feeder is back-fed from an alternative Feeder line with no co-ordinated heat pump management
4. Abnormal operation of the Feeder (N-1) condition where the Feeder is back-fed from an Alternative Feeder line with coordinated heat pump management.

See section 4 for information on coordinated heat pump management scenarios. In creating the input forecast data, the following assumptions were used:

Table 2: Study scenarios for analysis

Day	Year	Study	Community 2024 DFES Applied
1	Baseline	Baseline	Baseline
2	2026	Unabated Load Growth	2027
3	2027		2029
4	2028		2031
5	2029		2033
6	2030		2035
7	2026	Co-ordinated HP Controlled Load Growth	2027
8	2027		2029
9	2028		2031
10	2029		2033
11	2030		2035

Sizing the energy centre

The input data

VEPOD Ltd calculated the 48 half-hourly 'peak shaving requirement' values in kWh (i.e. how many kWh must be supplied by the REACH energy centre in each 30-minute window to keep the Feeder within its limit) based on Feeder demand forecasts supplied by NGED and knowledge of the maximum Feeder load. The data was converted from kVA to kWh, assuming a 0.95 power factor. The data shown in Table 3 below is for the BNZ Feeder 340040-0017 during abnormal Operation (N-1) and under a non-coordinated heat pump scenario.

Table 3. Half-hourly peak shaving energy requirements - BNZ Feeder 340040-0017 (N-1 abnormal operation).

Interval[1]	Energy (kWh)	Interval	Energy (kWh)	Interval	Energy (kWh)	Interval	Energy (kWh)
E_1	264.7	E_{13}	405.7	E_{25}	251.0	E_{37}	535.5
E_2	384.8	E_{14}	460.8	E_{26}	258.4	E_{38}	592.3
E_3	493.5	E_{15}	523.9	E_{27}	250.4	E_{39}	594.9
E_4	543.9	E_{16}	442.8	E_{28}	289.7	E_{40}	538.8
E_5	527.5	E_{17}	420.5	E_{29}	258.3	E_{41}	488.9
E_6	567.8	E_{18}	421.3	E_{30}	243.4	E_{42}	422.5
E_7	554.6	E_{19}	414.6	E_{31}	243.4	E_{43}	354.9
E_8	513.4	E_{20}	312.3	E_{32}	237.3	E_{44}	307.8
E_9	444.1	E_{21}	265.0	E_{33}	265.6	E_{45}	268.0
E_{10}	392.2	E_{22}	317.9	E_{34}	326.0	E_{46}	201.3
E_{11}	396.0	E_{23}	262.1	E_{35}	396.4	E_{47}	195.9
E_{12}	426.2	E_{24}	219.9	E_{36}	459.3	E_{48}	218.2

[1] E_1, E_2, ..., E_{48} are used for labelling each data point. For reference, this table shows 48 intervals of 30 min each. Each value is the ***energy* in kWh** required in that half hour.

The data indicates that the REACH energy centre would be required to continuously export power in the above fault condition scenario. There is thus no ability to recharge the batteries within the energy centre from the grid during the above-referenced scenario.

The approach used a 'peak shave' only case, which assumes that the genset is always available running constantly at the average export value with the battery storage system supporting the peaks and troughs of demand from the mean. This approach sees the generator running constantly at its rated capacity, providing sufficient power to the network for the average of each half-hourly value. When the half-hourly demand exceeds the amount supplied by the generator, additional power is provided from the batteries. When the half-hourly demand is below the generator output, the excess power produced by the generator is used to top up the batteries.

Sizing scenario – 'peak-shave only' case (genset always available)

In this scenario, it was assumed that the generator is always available and running constantly at its maximum rated power. The peaks and troughs of demand (above and below the amount of power supplied by the genset) are handled by a Battery Energy Storage System (BESS).

1. Compute basic stats

1. Number of half-hours per period: 48
2. Total energy to shave per day:

$$E_{\text{tot}} = \sum_{i=1}^{48} E_i \approx 18\,174.16 \text{ kWh}$$

3. Mean per half-hour:

$$\bar{E} = \frac{E_{\text{tot}}}{48} \approx 378.63 \text{ kWh}$$

2. Generator sizing

1. A half-hourly energy of 378.63 kWh corresponds to a power of:

$$P = \frac{\bar{E}}{0.5\ \mathrm{h}} \approx 757.3\ \mathrm{kW}$$

2. Add 10 % safety margin:

$$P_{\mathrm{gen}} = 757.3 \times 1.10 \approx \mathbf{833\ kW}$$

When the generator runs continuously at 833 kW, it can deliver in each half-hour:

$$E_{\mathrm{gen,hh}} = 833\ \mathrm{kW} \times 0.5\ \mathrm{h} = 416.5\ \mathrm{kWh}.$$

Any half-hour requirement above 416.5 kWh must come from the battery.

3. Compute battery discharge per period:

$$d_i = \max\big(E_i - 416.5,\ 0\big) \quad \Rightarrow \quad \sum_i d_i \approx 1\,642.5\ \mathrm{kWh/day}.$$

4. Account for 90 % round-trip efficiency:

$$E_{\mathrm{charge}} = \frac{\sum_i d_i}{0.90} \approx 1\,825.0\ \mathrm{kWh/day}.$$

5. Add 10% safety margin:

$$C_{\mathrm{batt}} = 1\,825.0 \times 1.10 \approx \mathbf{2\,008\ kWh} \quad (\approx 2.01\ \mathrm{MWh}).$$

Battery power (inverter/rectifier) rating

Breakdown of the battery's power-electronics sizing, based on the 833kW continuous generator:

1. Half-hourly baseline energy

$$E_{\mathrm{gen,hh}} = 833\ \mathrm{kW} \times 0.5\ \mathrm{h} = 416.5\ \mathrm{kWh}.$$

2. Discharge (inverter) side

   For each period i,

$$d_i = \max(E_i - 416.5, 0)$$

The maximum d_i is

$$\max_i d_i \approx 178.35\ kWh \quad \Rightarrow \quad P_{\mathrm{discharge}} = \frac{178.35}{0.5\ h} \approx 356.7\ kW.$$

+10 % margin ⇒ 392 kW

3. Charge (rectifier) side

Whenever $E_i < 416.5$, the surplus must be absorbed:

$$c_i = \max(416.5 - E_i, 0)$$

The peak is:

$$\max_i c_i \approx 220.57\ kWh \quad \Rightarrow \quad P_{\mathrm{charge}} = \frac{220.57}{0.5\ h} \approx 441.1\ kW.$$

+10 % margin ⇒ **485 kW**

Conclusion

- Battery inverter (discharge) rating: ~392 kW
- Battery rectifier (charge) rating: ~485 kW

Or, if a single bidirectional converter is used, size it for the larger figure (≈ 485 kW) or, more likely, a 0.5 MW nameplate.

Table 4: Sizing summary

Scenario	Genset Size	Battery energy	Battery power inverter rating
Model with no co-ordinated heat pump demand	833 kW	2.01 MWh	0.5 MW

Analysis of the battery energy State of Charge (SoC)

Figure 7 shows the State of Charge (SoC) of the BESS throughout the day. The scale on the left shows the state of charge in kWh. In practice, the minimum SoC should be no lower than 20% (0.4 MWh). This has been modelled to account for the losses incurred when charging and discharging the battery, known as the round-trip efficiency, ensuring that the SoC at the end of the day is equivalent to that at the start of the day. In this example, the initial charge is set at 1.5 MWh to account for the substantial initial draw from the network during the first phase of operation.

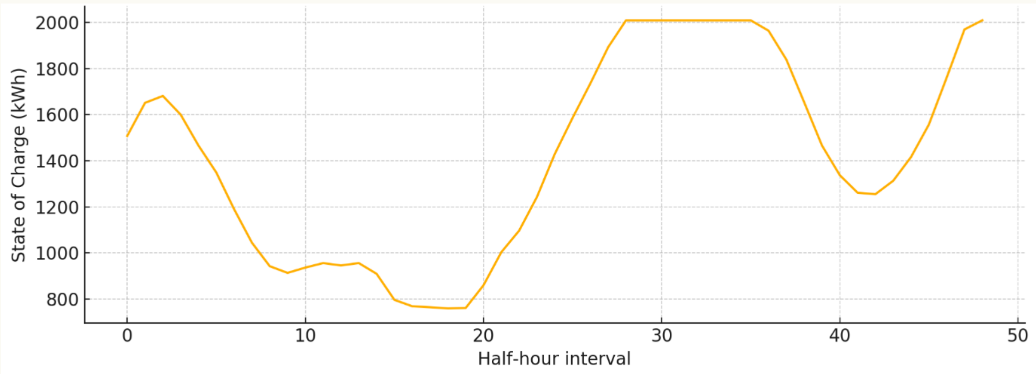


Figure 7: BESS SoC with 90% round-trip efficiency and 75% initial charge

Table 5: BESS performance summary

Metric	Results	Explanation
Initial SoC	1,508 kWh (75 %)	The battery starts the day at 75% charge capacity, equivalent to 1,508 kWh of stored energy.
Minimum SoC	≈ 758 kWh (37.7 %)	The battery's lowest point during the day is approximately 758 kWh, representing 37.7% of total capacity. This stays well above critical depletion levels.
Intervals at 100 % SoC	9 (28 → 36 & 48)	The battery reaches full capacity during nine half-hour intervals - specifically from periods 28 to 36 and again at period 48. During these times, the battery cannot accept additional charge.
Energy 'spilt' while the battery is full	≈ 285 kWh	When the battery is at 100% capacity, approximately 285 kWh of excess generator energy cannot be stored and is effectively wasted. This represents energy that could have been captured with a larger battery capacity.

VEPOD's key observations

1. Efficiency losses deepen every discharge and soften every charge. This was modelled by applying √0.90 ≈ 94.9 % efficiency on both charge and discharge legs, so a full round trip is 90 %.
2. The battery is never empty. Even with losses, the battery bottomed at ~758 kWh, well clear of zero, thanks to the 75% starting SoC.
3. Because the battery began three-quarters full, the mid-run surplus in intervals 22-36 pushes the battery to 100 % for nine consecutive half-hours. Any additional surplus during that plateau must be curtailed or diverted elsewhere.
4. Sizing remains adequate but could be optimised. If spilling ~285 kWh of potential storage is a concern, we could:
    - Trim the genset set-point slightly during the long charging stretch,
    - Add a little more BESS capacity, or
    - Export/curtail instead of charging once the battery hits its limit.
5. Round-trip losses cost about 93 kWh over the 48 intervals.
   (The sum of efficiency penalties applied during charge/discharge events.)

Effect of co-ordinating the heat pump demand on the sizing

Passiv is one of the REACH project partners with expertise in heat pump control systems. Their analysis, which can be found in section 4, demonstrates that a coordinated management approach can potentially reduce load demand peaks, directly impacting the required sizing of the REACH energy centre.

Based on the revised input data provided by NGED, which includes the effect of coordinated heat pump control, the above analysis steps were repeated for the same Feeder under abnormal load conditions to provide the following sizing result.

Table 6: Impact of heat pump coordination on hybrid system component sizing

Scenario	Genset size	Battery energy	Battery power inverter rating
Model with co-ordinated heat pump demand	794.6 kW	2.03 MWh	0.5 MW

Conclusion: What changed?

Coordinating heat pump demand significantly reduces the required system components:

- Generator: sizing dropped from ~ 833 kW → ~795 kW (≈4.6 % lower).
- Battery: from ~2.01 MWh → ~2.03 MWh (≈1% higher).

Indicative cost summary

Table 7: Indicative cost for a containerised 833 kW genset + 2 MWh BESS (0.5 MW PCS) ready for 11 kV grid connection (UK)

Cost element	Lean-spec (low)	Typical C&I spec (mid)	Premium/ fast-track (high)	Notes & key drivers
833 kW diesel generator (Tier IIIa, open-skid → super-silent)	£90k	£130k	£180k	Factory-gate pricing varies by engine brand, emissions tier, enclosure & warranty length.
2 MWh Li-ion battery incl. racks & BMS	£260k	£320k	£520k	Uses (Perkins 800KVA Generators - Reliable Power Solutions - pricing ≈ $115 /kWh and UK turnkey uplifts (25–60%).
0.5 MW bidirectional PCS	£17k	£25k	£45k	ENF list (Lithium-ion battery pack prices fall 20% in 2024) or ATESS PCS500 gives ≈ £17k; UK stock & grid-code firmware add margin.
EMS, SCADA & protection relays	£10k	£15k	£25k	G9 Atess Power Technology
1 MVA 11 kV/0.4 kV oil-filled transformer	£35k	£45k	£70k	New Tier-2 Ecodesign unit; dry-type or ester-filled adds 15–30%
11 kV RMU + metering panel	£30k	£37k	£45k	National Grid budget price £25k (RMU) + £12k (metering).
Container fabrication (ISO 40 ft), HVAC, fire suppression, cabling, LV switchboard	£80k	£110k	£150k	Dual-compartment design (diesel vs battery) & DSEAR zoning drive cost
Factory integration + FAT/SAT	£45k	£55k	£75k	Mechanical fit-out, wiring looms, soak-testing
Site delivery, civils, commissioning & DNO witness	£70k	£90k	£160k	Pad, crane lift, 11 kV cable tails (<50 m) and G99 paperwork

Table 8: Ball-park project totals (ex-VAT)

Scenario	CAPEX
Lean/minimum spec	≈ £620k
Typical turnkey	≈ £890k
Premium / accelerated schedule	≈ £1.25–1.35m

(Derived by summing the column figures in the previous table; ±20 % accuracy for feasibility budgeting.)

Table 9: Reasons for cost variation

Cost driver	Effect on CAPEX
Specification choices	Acoustic canopy vs open skid (adds £20-40k) – This would ensure a quieter operation, which, depending on location, maybe a key requirement; Tier 4-Final emissions kit (+10 %).
Battery chemistry and warranty	LFP vs NMC, 10- vs 15-year throughput guarantees can swing £80-150k on a 2 MWh system.
Container layout	Single ISO 40 ft with the fire wall is cheapest; two dedicated 20 ft modules or a walk-in switch room add £40-60k.
Grid requirements	DNO auxiliary supply, neutral-point earthing resistors or harmonic studies may add £20-40k.
Schedule & origin	EU-built equipment shortens shipping time but lifts hardware by 10-15 %; fast-track build slots add overtime premiums.
Soft costs & risk	EPC wrap, performance bonds and indexation allowances typically run 10-20 % of hardware but climb if finance parties require longer LD cover.

- The central £890k figure assumes mainstream brands (Cummins, CATL/LFP racks, ATESS PCS), 12-week lead, standard noise (75 dBA @ 1 m), and a single 40 ft container with internal fire partition.
- Grid connection fees, fuel system bund wall, standby fuel and land purchase are *excluded* as they depend heavily on on-site specifics.
- Costs are referenced to Q2 2025, GBP terms, and should be uplifted by ~3-4 % / yr for budgeting beyond 2025 based on BEIS plant-cost indices.

These numbers are suitable for an early-stage feasibility analysis; expect ±20 % accuracy until supplier RFQs are obtained.

4 Smart heat control assessment

A summary of Passiv's assessment of the potential for electrified heat with smart controls in the Bigbury Net Zero area

Introduction

This section details a proof of concept of how cross-home coordination could be applied to **minimise aggregate load across communities** with high penetrations of Passiv Smart Thermostats (PSTs) and high LCT uptake. The goal of this modelling was to demonstrate this capability and highlight the power of dense deployments of coordinated smart controls, when compared to other strategies for mitigating peak demand.

This contrasts with the previous section, which investigated a more realistic modelling scenario where only community homes installed PSTs, making up a small subset of the total homes on a selected Feeder. The modelling then evaluated the benefits of **minimising aggregate load at the Feeder level**, when deploying coordinated controls on a smaller scale.

This section contains the detailed assumptions underlying the modelling, and sample outputs are provided for transparency.

Passiv modelling aims

The economic efficiency of the modular energy centre as a solution supporting local decarbonisation depends heavily on the uptake of EVs and low-carbon heating systems.

To evaluate this, it's important to simulate the energy demand of each home in the community in various future energy scenarios.

Simulated typical community heat pump loads and worst-case (coldest winter) scenarios can inform the optimal sizing of the modular energy centre.

Passiv aims to show how optimised smart controls and coordinated control strategies can mitigate the peak worst-case scenario aggregate electricity demands across the community.

What are smart controls?

Traditional heating controls often don't work as well with heat pumps. Most conventional thermostat options used on existing heat pump installations were designed for gas boilers or air conditioning units. These systems can lead to heat pumps failing to meet room setpoints, running at high flow temperatures, and cycling on and off, causing inefficiencies, high heating bills, and negative perceptions of the new heating system. They often also lack the connectivity to allow control via smartphone and futureproofing against time-of-use (ToU) tariffs and flexibility opportunities.

The PST is designed specifically for heat pumps, turning any heat pump into a smart, connected device that can follow dynamic ToU tariffs or provide flexibility to the energy system without compromising comfort. The PST simplifies heat pump operation, learns how a home heats and cools, and provides intuitive control via an in-home thermostat, programmer, or smartphone app. It can help to reduce heating bills using advanced machine learning to adjust flow temperatures and optimise for smart tariffs and solar PV. The PST also provides grid flexibility through automated demand-side response (DSR).

Heat demand modelling: Objectives

- Simulate the heat demand of homes in the Bigbury Net Zero (BNZ) community to estimate the additional electricity demand from the transition from gas boilers to hybrids and heat pumps.
- These heat pump electricity profiles can be added to baseload and EV electricity profiles. This gives realistic forecasts of electricity demands from electrifying heat with low-carbon heating systems.
- This allows for the simulation of future energy scenarios with varying heat pump and EV penetration levels and for modelling the impact on the aggregate load at the community level.

Heat demand modelling: Approach

Passiv chose a set of 20 house archetypes (which will be duplicated and mapped onto the real houses in each community). These 20 archetypes represent the full range of houses in terms of physical size and occupants. They also encompass the diversity of space heating and hot water demand patterns.

For each archetype, two simulation runs are carried out at a half-hourly resolution across a whole year to create heat pump electricity profiles in two weather scenarios:

- Typical year - to provide examples of typical heat pump operation
- Coldest year - to ensure peak demand is represented.

The heat pump operates under standard manufacturer controls (with a time clock with optimum start and weather-compensated flow temperature), an example of how heat pumps could operate without any smart controls.

Methodology

Determining house archetypes

- Each community is simulated using 20 archetypes, using a unique digital twin.
- These digital twins have randomised thermal dynamics and a heat transfer coefficient consistent with the house size.
- Each archetype is assigned an occupancy type and work type, which affects the choice of heating schedule, heating setpoint and hot water consumption profile (which impact heat pump usage patterns).
- Passiv assigned specific low-carbon heating systems to each housing archetype, ensuring that the distribution of heating systems across archetypes matched the energy scenarios modelled for these communities.
- Passiv ensured balanced representation by duplicating each archetype several times when mapping them to actual houses. This approach allows them to extrapolate individual heat loads more accurately to estimate the total community-level energy demand.

Heat demand modelling: Occupancy and work

- For BNZ, ONS data from Bigbury in South West England informed the type, number of occupants, and work patterns used.
- It was noticeable that Bigbury had a much higher proportion of older occupants and retirees than the national average. This was reflected in our archetype selection.
- The majority of households had two occupants.

Heat demand modelling: House size

- EPC data was used to determine the houses' total floor areas (TFA).
- For each community, quantiles at 20 evenly-spaced points were sampled from the sample distributions.
- These floor areas were fed into the models to estimate heat demands.

Heat demand modelling: Heating systems

- 2024 DFES (Electric Engagement pathway; see the NGED DFES map for more information) scenarios for 2035 and 2050 were used to allocate heating systems to archetypes proportionally.
- Ground source heat pumps and heating systems with thermal stores were more likely to be assigned to larger houses.
- Only low-carbon electrified heating systems were modelled, as these contribute to the aggregate electricity load.

Table 10. Projected distribution of low-carbon heating technologies in the BNZ community (Baseline, 2035, and 2050)

Community	Technology	Baseline	2035	2050
BNZ	Hybrid	0	17	15
BNZ	Non-hybrid ASHP	43	79	104
BNZ	Non-hybrid ASHP + thermal storage	0	15	37
BNZ	Non-hybrid GSHP	6	13	21
BNZ	Non-hybrid GSHP + thermal storage	0	7	15

House archetypes

The 20 archetypes for BNZ are summarised in Table 11.

- The floor areas were large; hence, the corresponding simulated heat demands were higher.
- The work and homeowner types reflect the higher proportion of older and retired occupants.

Table 11: House archetypes for the BNZ community by total floor area, heating system, household composition, occupancy pattern and thermal storage status

TFA	Heating system type	Homeowner type	Work type	Thermal store
63	Heat Pump	Single	Full time	No
71	Heat Pump	Couple	Full time	No
74	Heat Pump	Old	Retired	No
80	Heat Pump	Couple	Full time	No
82	Heat Pump	Old	Retired	No
84	Heat Pump	Family	Full time	No
87	Heat Pump	Couple	Part time	No
89	Heat Pump	Family	Full time	No
95	Heat Pump	Single	Full time	No
104	Heat Pump	Old	Retired	No
110	Heat Pump	Couple	Full time	Yes
115	Hybrid Heat Pump	Old	Retired	No
126	Heat Pump	Couple	Full time	No

133	Heat Pump	Old	Retired	Yes
149	Ground Source Heat Pump	Couple	Part time	No
153	Heat Pump	Family	Part time	Yes
166	Ground Source Heat Pump	Old	Retired	No
190	Hybrid Heat Pump	Old	Retired	No
215	Heat Pump	Family	Full time	No
264	Ground Source Heat Pump	Family	Part time	Yes

Modelling of heating setpoints and schedules

Each archetype has a randomly generated schedule and setpoint, dependent on the occupants and their working schedule. For example, Figure 8 represents retired occupants, who are more likely to be at home during the day, with the house warmer.

- Three left panels: Heat maps showing patterns from real customer data, where:
  - Panel 1: Shows when people start heating in the morning and for how long
  - Panel 2: Shows when people start heating in the evening across days of the week
  - Panel 3: Shows what temperature settings people use in the morning hours
  - The brightest spots (yellow/red) show the most common combinations. For example, in panel 1, many households start morning heating around 7:00 AM for about 2 hours, while panel 3 shows many people set their thermostats to around 21°C during morning hours.
- Right panel: A sample heating schedule showing temperature settings throughout a typical day, with higher temperatures during morning and evening occupied periods.

These patterns vary by household type - for instance, retired residents tend to maintain warmer temperatures throughout the day since they're home more often.

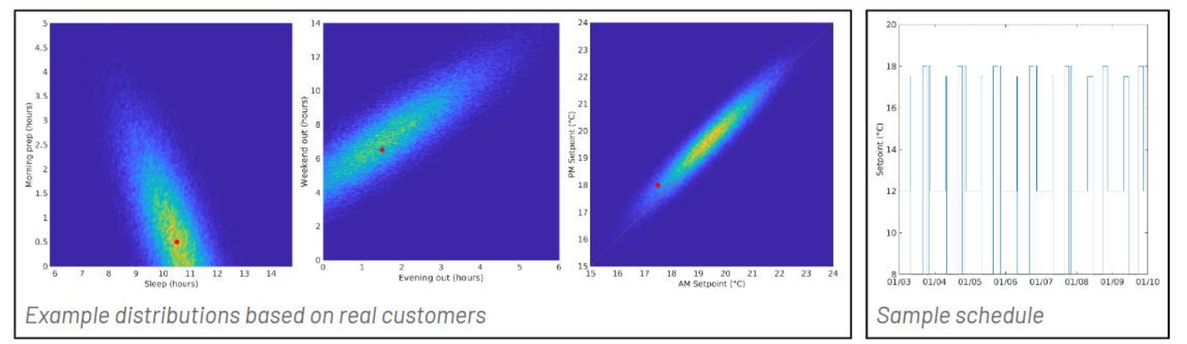


Figure 8: Real-World Heating Behaviour Patterns and Sample Schedule Across Different Household Types

Domestic hot water modelling

Hot water usage was estimated per month for each archetype based on the number of occupants (Standard Assessment Procedure (SAP) assumptions, the UK government's recommended method system for measuring the energy rating of residential dwellings)

The modelling used real consumption patterns (from previously monitored homes) chosen to match similar monthly consumption. Yearly consumption profiles were created for the simulations (more accurate than a simple demand profile).

Figure 9 shows the hot water consumption rate (L/h) from a 134 l thermal storage tank across an entire year. The lower graph provides a detailed one-week view (highlighted in orange in the main graph), revealing the daily rhythms of hot water usage with distinct usage peaks.

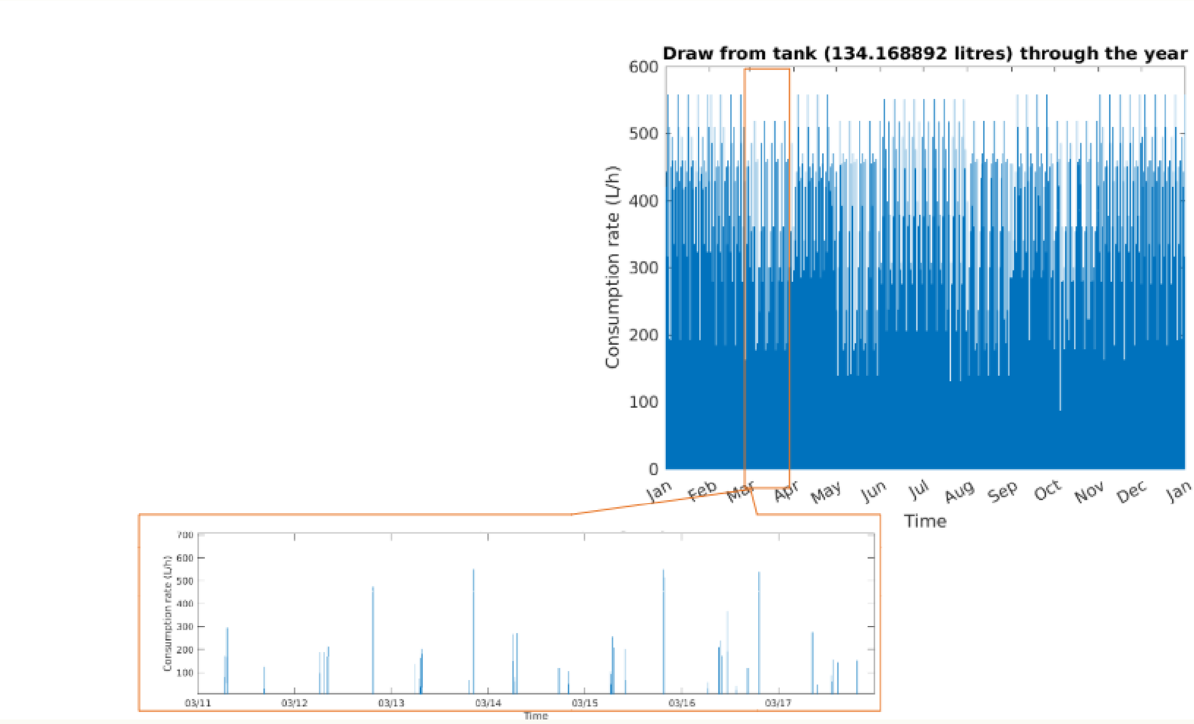


Figure 9: Annual and weekly hot water consumption patterns from thermal storage tank

Weather data

Weather data was used from Plymouth, the nearest weather station to the BNZ community. For the coldest weather scenario, 2018 weather data was used, as this year had a prolonged cold spell ('Beast from the East'), allowing for an assessment of the impact of the 'worst case' weather scenario on the aggregate community demand.

Typical Meteorological Year (TMY) weather data was used for more typical profiles. The TMY data is selected by analysing historical data and finding real months that best match the long-term averages of daily min/max temperature and irradiation.

Figure 10 compares external temperature patterns during February and March using two weather datasets for the BNZ community. The graph shows daily temperature fluctuations from the Typical Meteorological Year (TMY) dataset (dark blue) alongside actual 2018 temperature recordings (light blue) from the nearest weather station. The 2018 data captures the 'Beast from the East' cold spell in late February when temperatures dropped below -5°C, creating worst-case conditions for heating.

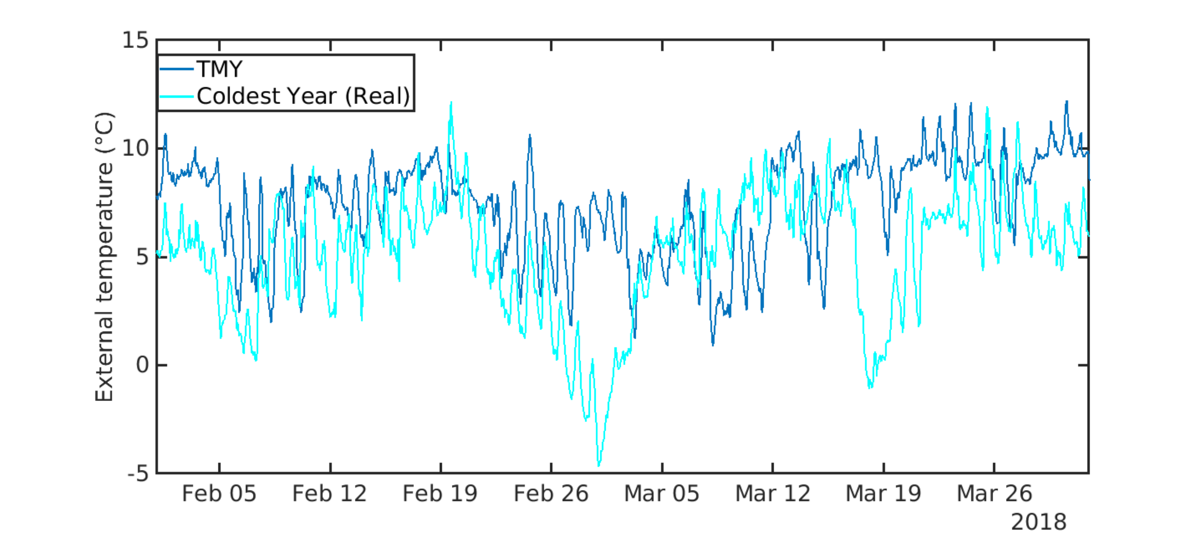


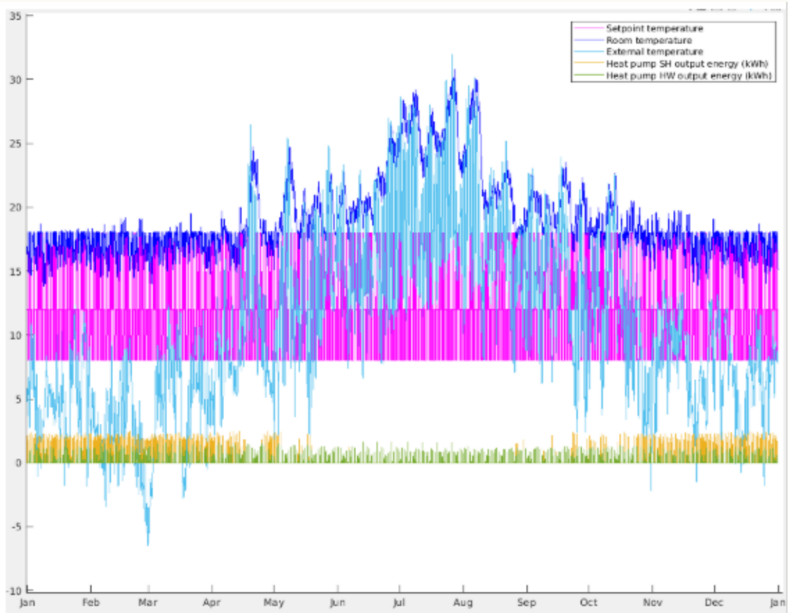
Figure 10: Comparison of Typical Meteorological Year (TMY) vs. coldest year (2018) external temperatures for BNZ Community

Annual forecasts

The Passiv annual forecasting tool was used to simulate the electrical demand from the heat pump for each archetype (see Figure 12).

This tool allows us to forecast detailed energy demand at half-hourly intervals throughout a whole year. This allows load profiles and running costs to be predicted for different heating system options and low-carbon technology configurations.

Figure 11 illustrates seasonal operation patterns, with higher space heating energy output during winter months (Jan-Mar, Nov-Dec) when external temperatures are lowest. During summer months (Jun-Sep), the heat pump operates primarily for hot water production with minimal space heating. The visualisation demonstrates how room temperature tracks the setpoint while responding to external temperature fluctuations throughout the year.



An example plot of a subset of annual forecast outputs

Figure 11. Annual Heat Pump Performance Indicators with Seasonal Variations

Scenario modelling: Approach

- Uses 2024 DFES (Electric Engagement pathway; see the NGED DFES map for more information) scenarios for 2035 and 2050 to find the number of each low-carbon asset in the community.
- Produce a total non-heat electricity load profile (EV usage plus other ‘baseload’) for each community in these scenarios.

- Map each low-carbon heating system in the community to one of the 20 archetypes used for the heat demand simulations.
- Calculate the aggregate demand (non-heat load plus heat load) resulting from the simulations in the case with standard manufacturer controls and the coldest weather conditions (coldest 2 days).
- Investigate whether aggregate demand can be decreased using a simple switch-off command at times of peak load.
- Run Passiv optimisation and inter-home coordination on all heating systems to minimise aggregate load whilst maintaining user comfort.

Scenario modelling: predicted community asset uptake

- DFES 2024 (Electric Engagement pathway; see the NGED DFES map for more information) scenarios for 2035 and 2050 were used to find the numbers of each low-carbon asset in the community.
- Each archetype is replicated, such that the total number of each heating system aligns with the predicted DFES scenarios.
- The number of EVs was also determined using these scenarios.
- There are 383 MPANs in Bigbury Net Zero (BNZ). This was used to determine the number of baseload profiles used.

Table 12: Projected low-carbon technology deployment in the BNZ Community Based on DFES 2024 Electric Engagement Pathway

Community	Technology	Baseline	2035	2050
BNZ	Hybrid	0	17	15
BNZ	Non-hybrid ASHP	43	79	104
BNZ	Non-hybrid ASHP + thermal storage	0	15	37
BNZ	Non-hybrid GSHP	6	13	21
BNZ	Non-hybrid GSHP + thermal storage	0	7	15
BNZ	EV	19	428	500

Findings

Heat demand modelling: Results

Figure 12 includes example outputs from the annual forecast simulations, showing average heat pump electricity demand profiles for the month of January in typical weather conditions. Three different archetypes from the BNZ community are shown.

The graphs show scheduled setpoints, achieved room temperatures, and heat demand (in kWh per half hour). Heat pump demand varies significantly from archetype to archetype. Here, the largest archetype is compared to two of the smallest. Different occupancies also cause changes in heating patterns.

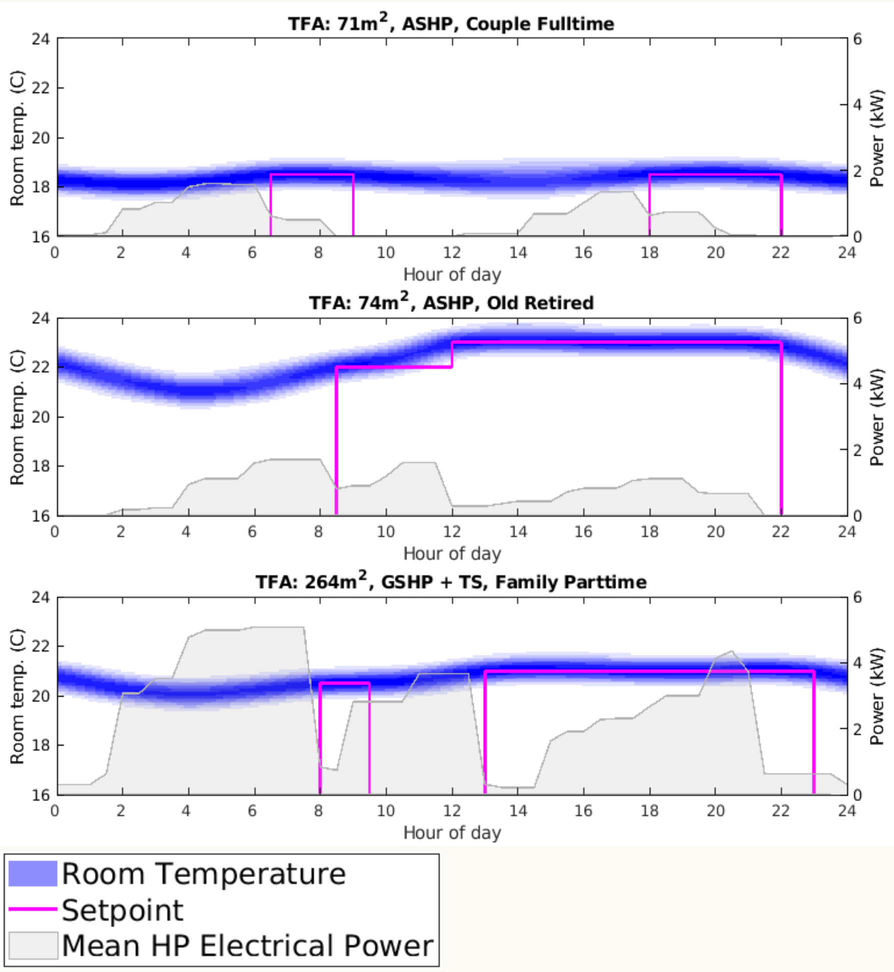


Figure 12: Comparison of daily heating profiles across three house archetypes in January

Figure 12 illustrates the daily heating patterns for three house archetypes during January under typical weather conditions. Each panel displays room temperature (blue bands), temperature setpoint (pink line), and mean heat pump electrical power consumption (grey area) over the day.

The top panel shows a smaller home (71m^2 TFA) occupied by a full-time working couple, with focused heating periods in the morning and evening. The middle panel depicts a similar-sized home (74m^2 TFA) with retired occupants, showing a warmer, more consistent heating pattern throughout the day. The bottom panel represents a much larger home (264m^2 TFA) with a part-time working family and thermal storage, demonstrating higher power consumption with more complex heating patterns and increased variability.

These profiles highlight how dwelling size, occupancy patterns, and heating system type significantly influence energy consumption and indoor temperature profiles, with larger homes requiring substantially more energy and different household types having distinctly different heating schedules and temperature preferences.

Heat demand modelling: Coldest days

Heat pumps were sized such that they were capable of meeting heating demands at all times. However, on the coldest days of the year, some heat pumps can provide more flexibility than others.

Figure 13 shows a simulated heat pump with a thermal store that has to preheat to meet the second day's 21.5°C evening setpoint. This is despite consistently running at the maximum electrical power output of the heat pump and discharging the thermal store. Much flexibility cannot be procured for homes like this without violating the householder's requested comfort.

Figure 14 shows a more typical case where the heat pump runs hard most of the time in the coldest weather but still keeps the house sufficiently warm and has some room for flexibility.

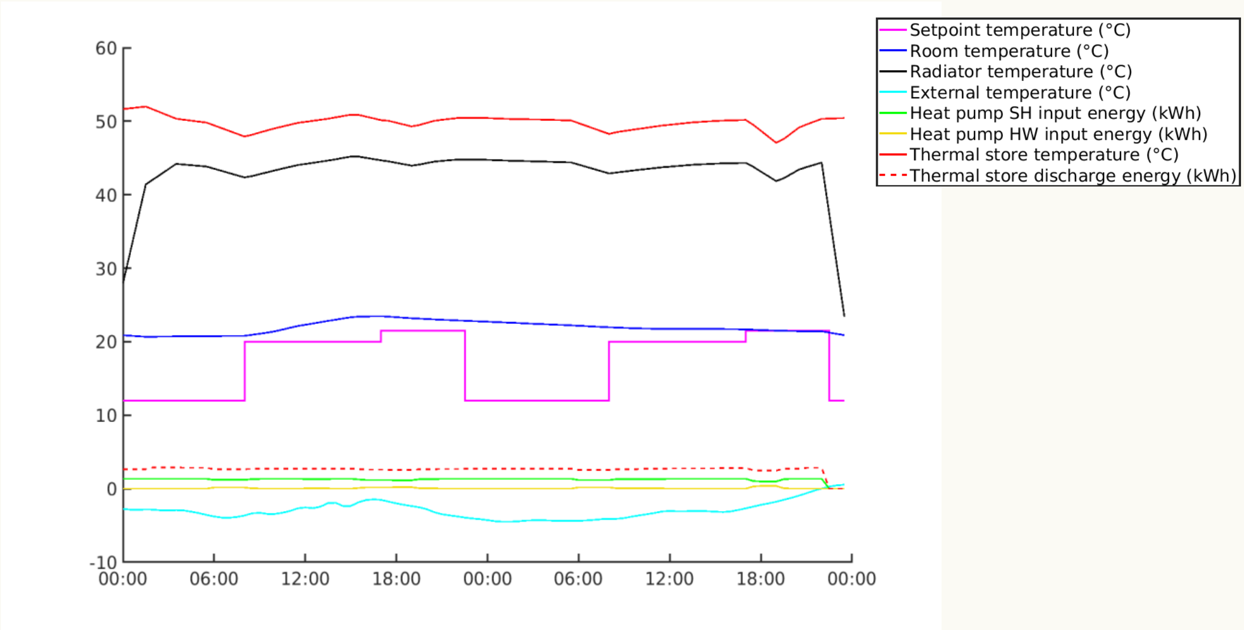


Figure 13: Heat pump performance during extreme cold weather with and without flexibility (1 of 2)

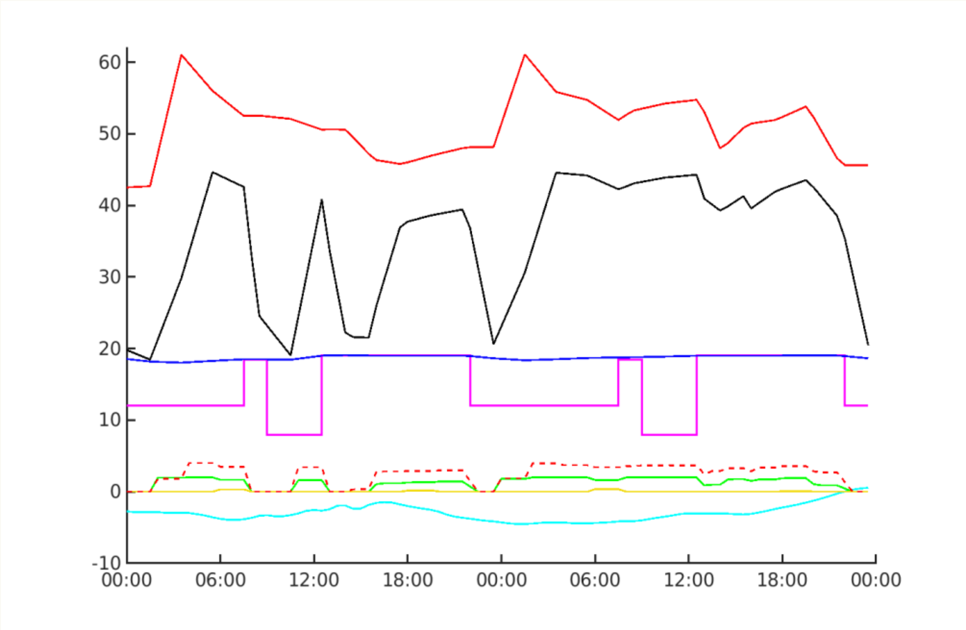


Figure 14: Heat pump performance during extreme cold weather with and without flexibility (2 of 2)

Modelling non-heat load

Diversified EV and baseload profiles provided by National Grid were used to simulate non-heat loads (see Figure 15). EV profiles are characterised by high overnight usage (green line), whilst other baseload usage follows a high usage pattern during the morning and evening hours.

Non-heat, non-EV baseload is assumed to be constant. Increased EV uptake between 2035 and 2050 causes a small increase in non-heat load (Black line). If EV chargers are not controlled intelligently, the largest peaks occur overnight.

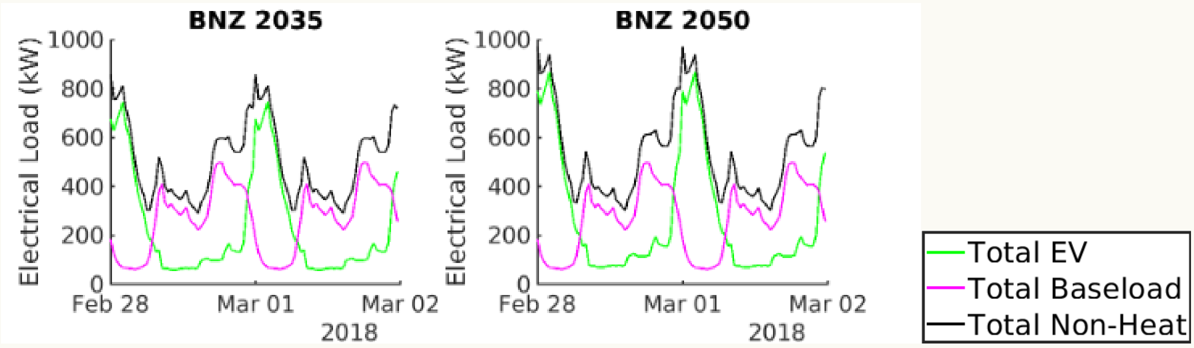


Figure 15: Projected community electrical load components for BNZ in 2035 and 2050

Modelling total electrical load (standard controls)

In the coldest conditions, heat pumps are running near their capacity most of the time. Even with an optimum start and time-clock control strategy, the heat pumps must run throughout the night to hit any morning setpoints. This results in even higher demand during the EV peak and becomes more of a problem in 2050, as heat pumps become a larger proportion of the total load.

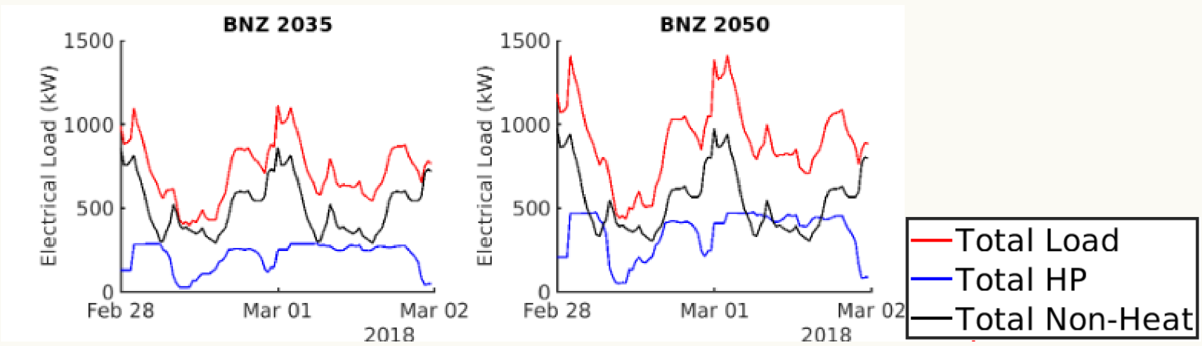


Figure 16: Total community electrical load composition for BNZ during peak winter days (2035 vs 2050)

Modelling total electrical load (standard controls + simple turnoff)

Passiv simulated a scenario where the modular energy centre sends an automated command to adjust heat pump settings to turn off for two hours in individual homes. This was scheduled overnight on 1 March between 00:00-02:00 (when the existing EV charging peak occurred).

This duration is insufficient to avoid the peak, as the EV peak lasts longer than this. Immediately after, most heat pumps turn back on at near maximum power, causing an issue at 02:00.

Figure 18 shows that the two-hour heat pump switch-off (00:00-02:00 on March 1) temporarily reduces electrical demand during the EV charging peak. By 2050, this rebound effect will become more pronounced as heat pumps constitute a larger proportion of the total load.

The duration of the switch-off is insufficient to fully address the overnight EV charging peak, which extends beyond the two-hour intervention period.

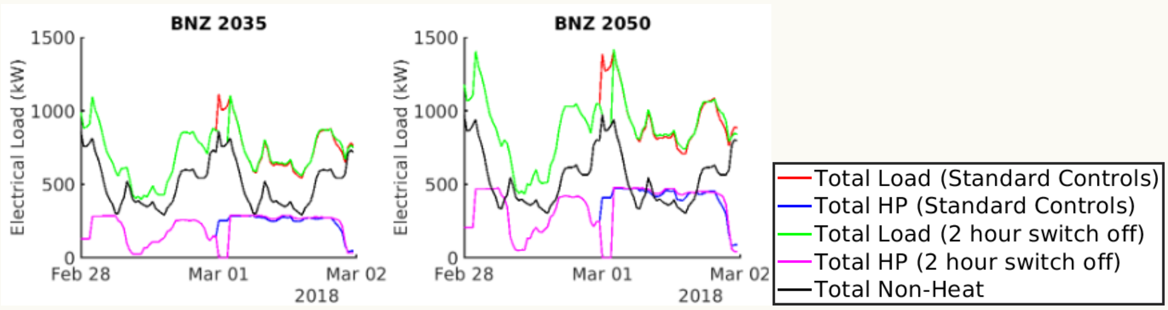


Figure 17: Impact of two-hour heat pump switch-off strategy on BNZ community electrical load (2035 vs 2050)

Modelling total electrical load (energy centre automated command)

Passiv also simulates a scenario where the modular energy centre sends an automated command to adjust heat pump settings to turn off for six hours in individual homes. This was scheduled overnight on Feb 28/March 1st between 22:00-04:00 (when the existing EV peak occurred). This does reduce the overnight peak in all cases. However, this greatly impacts householder comfort.

Figure 18 illustrates the effects of an extended heat pump control strategy on the BNZ community's electrical demand during three consecutive cold winter days.

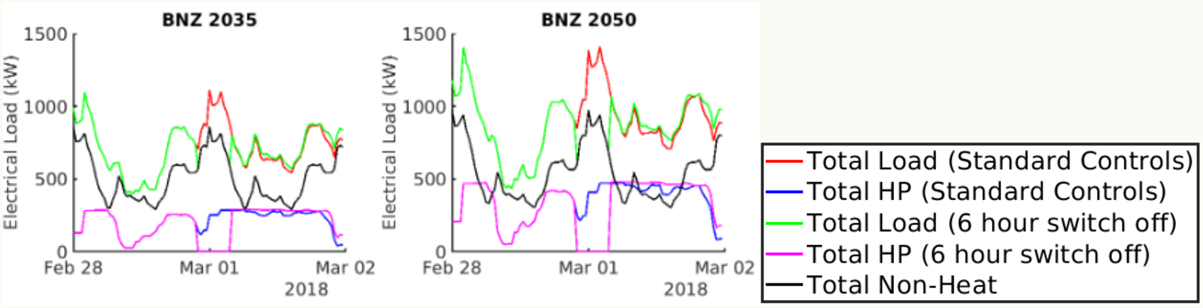


Figure 18: Impact of extended six-hour heat pump switch-off strategy on BNZ community electrical load (2035 vs 2050)

- Although the peak overnight demand is reduced in all cases, turning off the heat pump for 6 hours is not an acceptable solution as the householders will be cold the next day.
- For the archetype shown in Figure 19, the turn-off period causes a major drop in indoor comfort and system performance over 48 hours.
- The heat pump has to run at its maximum power and flow temperature for the next day, yet it never recovers to hit the requested setpoint.

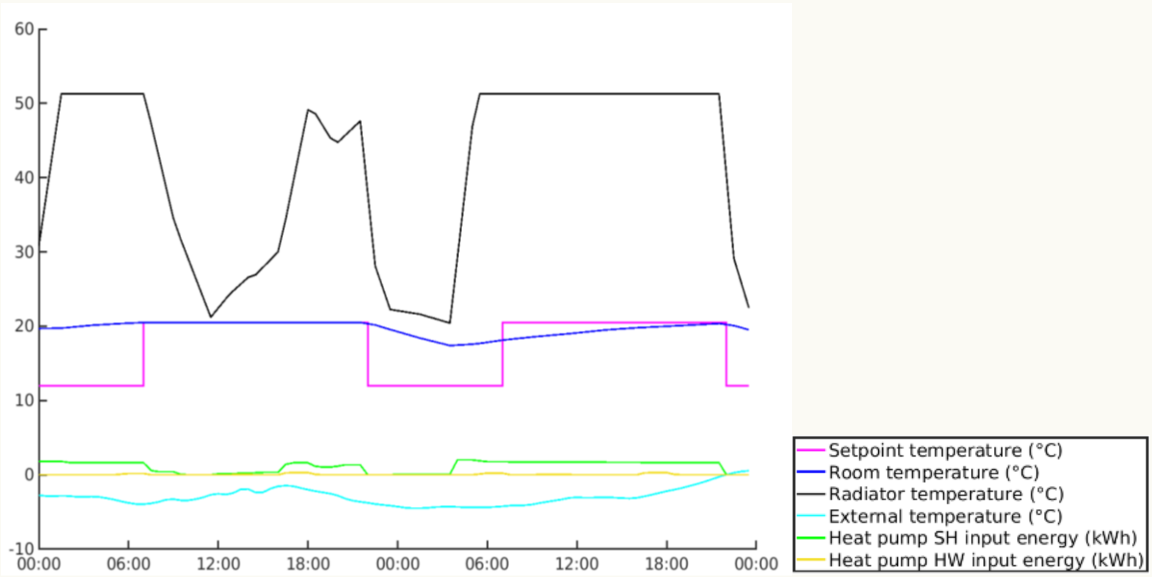


Figure 19: Impact of extended heat pump switch-off on thermal comfort and system recovery

Modelling total electrical load (Passiv optimisation + coordination)

Passiv coordination attempts to restrict aggregate power to set levels within certain periods in this scenario. Passiv set up the maximum power limits to flatten the load as much as possible.

This results in a much flatter demand profile and can work around the overnight EV spike without compromising comfort (allowing each home to be a maximum of ~0.5°C under setpoint).

Figure 20 illustrates the effects of coordinated heat pump management strategies on the BNZ community's electrical demand during three consecutive cold winter days.

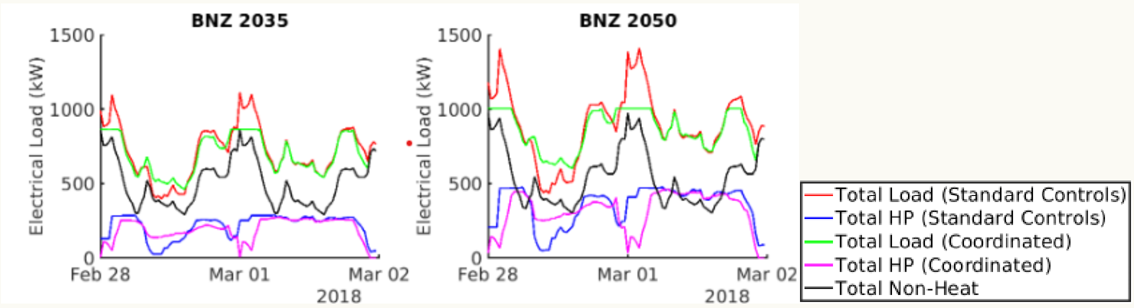


Figure 20: Comparison of standard controls vs coordinated heat pump operation in BNZ community (2035 vs 2050)

The following simplified graphs (Figure 21) show standard controls vs coordinated controls side by side, demonstrating how Passiv can flatten the load and reduce peak demands. The 2050 scenario shows a greater impact from coordination as heat pumps represent a larger proportion of the total electrical load.

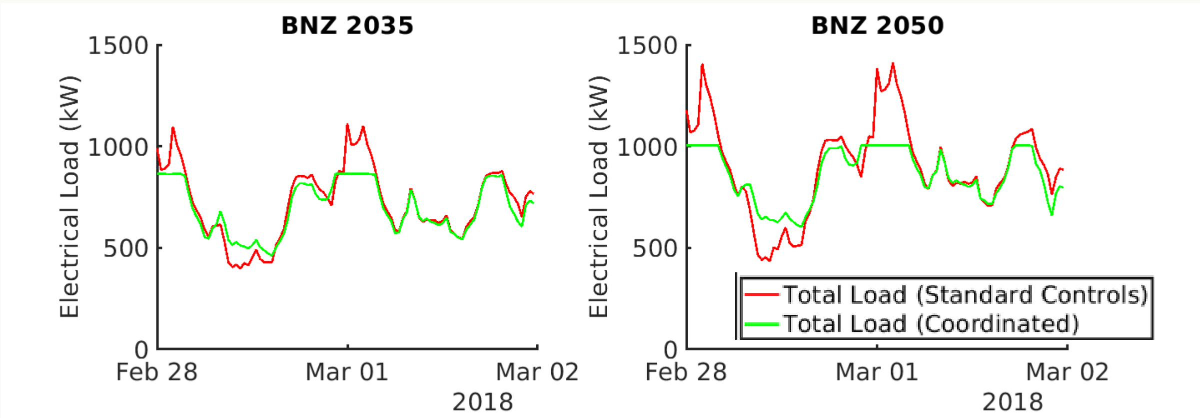


Figure 21: Comparison of standard controls vs coordinated heat pump operation in BNZ community (2035 vs 2050)

Sample coordination behaviour: Hybrid

Figure 22 shows how a hybrid system would operate during this period under coordination in the BNZ community.

The hybrid system is likely to run the boiler in cold conditions regardless, as it is more cost-effective to do this. Hence, it can meet the householder's comfort and honour a 0 kW maximum electrical power at any time. Hybrid heating systems offer advantages for procuring flexibility without resulting in downsides for the occupants' comfort.

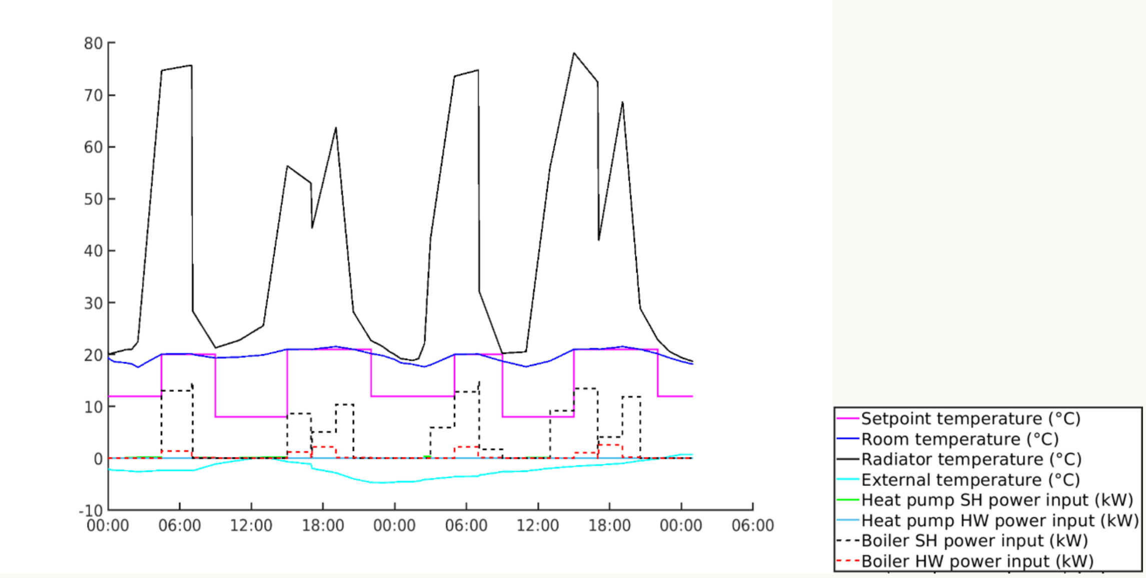


Figure 22: Coordinated operation of a hybrid heat pump system during cold weather period

Sample coordination behaviour: GSHP

Figure 23 illustrates the optimal operation of a ground source heat pump (GSHP) under coordinated control over a 48-hour cold weather period in the BNZ community. The heat pump reduces overnight electricity usage during peak EV charging times while maintaining room temperature (blue line) close to the setpoint (pink line) throughout the period, demonstrating demand flexibility without compromising occupant comfort.

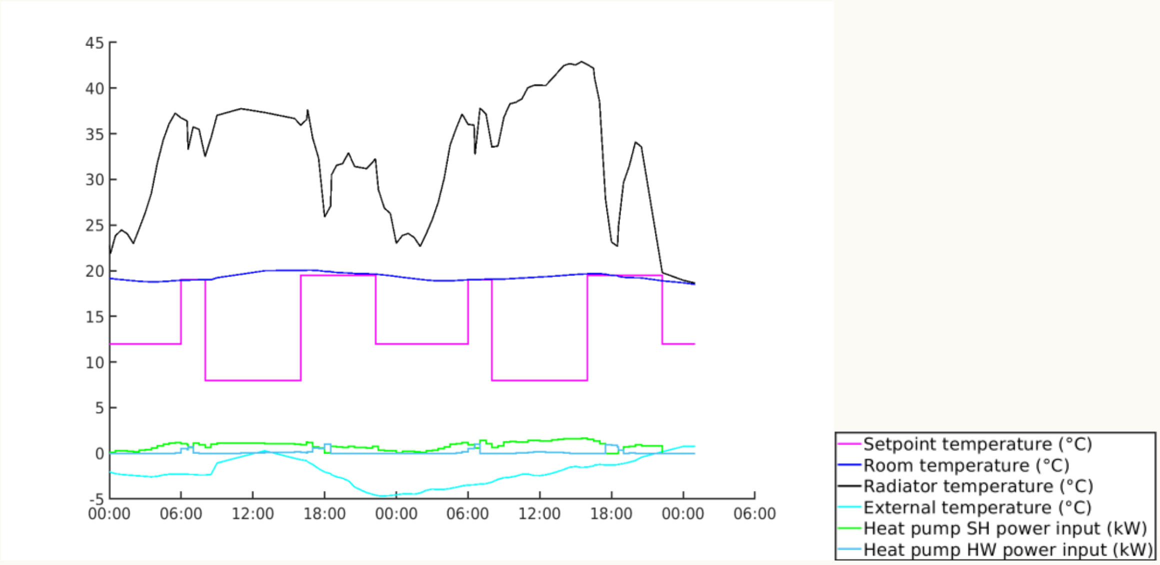


Figure 23: Coordinated operation of a ground-source heat pump during cold weather period

Sample coordination behaviour: ASHP + thermal store

Figure 24 shows how an air source heat pump (ASHP) with a thermal store would operate optimally during this period under coordination in the BNZ community.

The thermal store provides additional flexibility by allowing the thermal store to discharge during the overnight signal to reduce power. As a result, the heating system can still hit the desired setpoint in the morning.

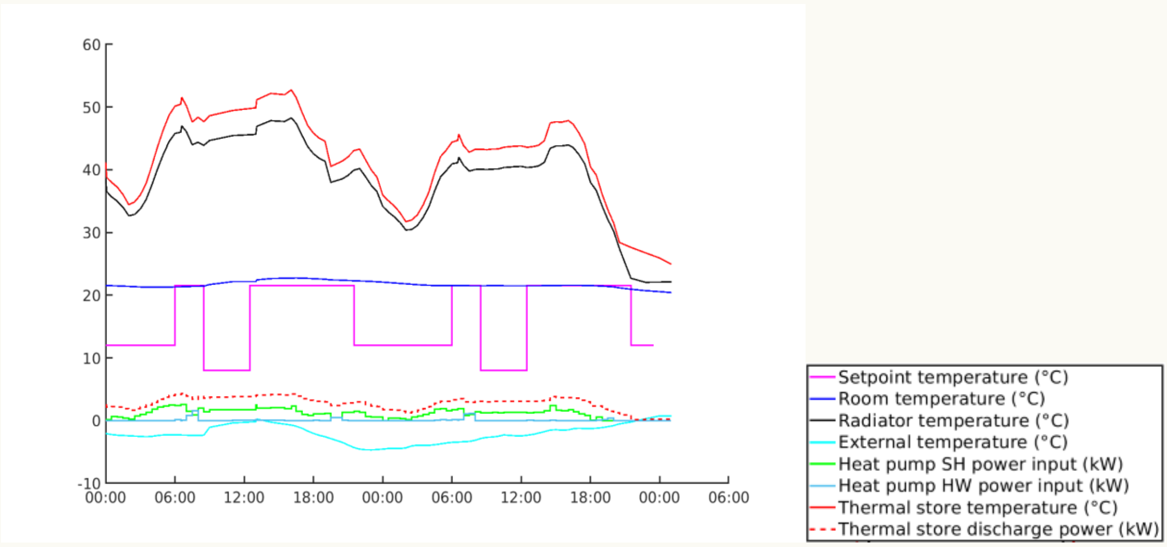


Figure 24: Heat pump operation with thermal storage during cold weather period

Modelling total electrical load (aggregate load comparison)

Figure 25 compares four heat pump control strategies and their impact on the total electrical load in the BNZ community during three consecutive cold winter days.

Passiv controls reduce the peak load by coordinating across all homes to create a flatter demand profile. Passiv coordination provides a similar or better reduction in peak load in all scenarios than a simple switch-off method. This could reduce the required capacity of the energy centre.

Note that control strategies impact householder comfort differently. In particular, the 6-hour switch-off scenario greatly impacts householder comfort, whereas the Passiv coordination scenario ensures comfort is maintained.

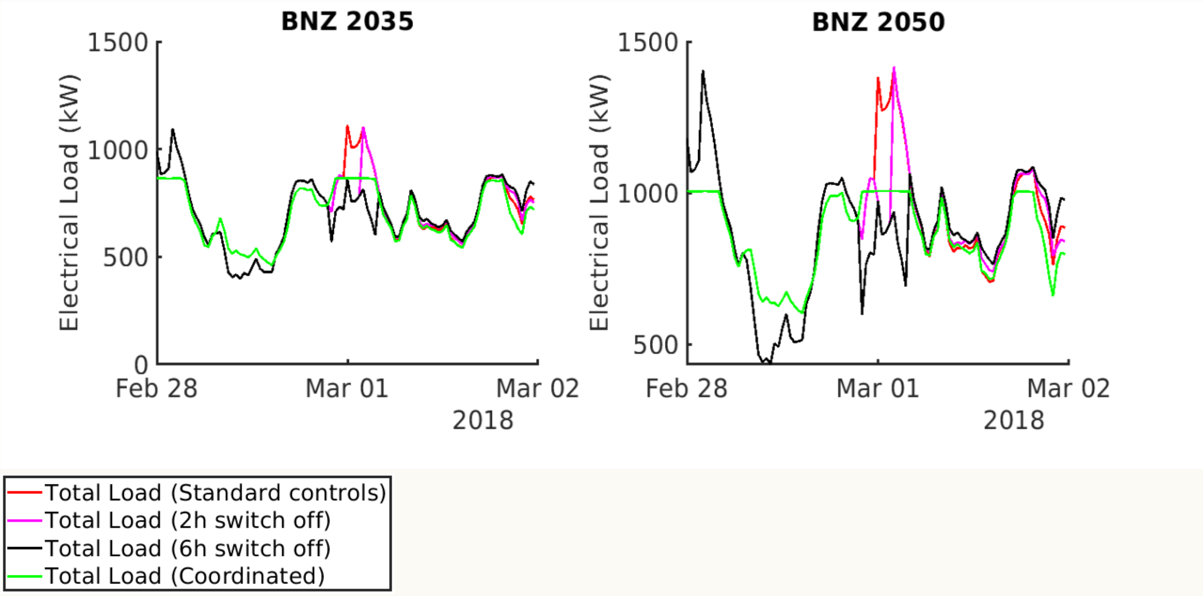


Figure 25: Comparison of total electrical load management strategies in BNZ (2035 vs 2050)

Table 13 shows the peak load (kW) in BNZ on the evening/morning of Feb 28th/March 1st, with various control strategies. Results are shown for both 2035 and 2050 scenarios, demonstrating the relative effectiveness of each approach in reducing peak demand as heat pump adoption increases.

Table 13: Peak electrical load (kW) in the BNZ community under different control strategies (Feb 28-Mar 1, 2018)

Scenario	Standard controls	Standard controls + 2h switch off	Standard controls + 6h switch off	Passiv coordination
BNZ 2035	1,112	1,104	860	865
BNZ 2050	1,411	1,416	1,065	1,006

Modelled comfort comparison

Table 14 shows the maximum room temperature deviation below the requested setpoint in the most impacted home within the BNZ under four different control strategies. Results are shown for both 2035 and 2050 scenarios, highlighting the thermal comfort implications of each demand management approach.

Passiv coordination provides comparable comfort to standard non-smart controls at the worst homes, allowing only a maximum of ~0.5°C under setpoint. This is also more equitable, as homes switch off according to their ability to provide flexibility while ensuring that no individual home is particularly cold.

As shown previously, switching heat pumps off without coordination means some householders will be cold for the following day.

Table 14: Maximum temperature deviation below setpoint (°C) in the worst-affected home under different control strategies

Scenario	Standard controls	Standard controls + 2h switch off	Standard controls + 6h switch off	Passiv coordination
BNZ 2035	0.19	0.98	2.57	0.50
BNZ 2050	0.19	0.98	2.57	0.52

Table 15 presents a thermal discomfort metric, calculated as the total 'degree-hours' below the desired room temperature setpoint averaged across all homes in BNZ. Results compare four different control strategies across 2035 and 2050 scenarios, quantifying the comfort impact of each demand management approach.

Here, the BNZ 2050 coordinated scenario causes more 'discomfort' over more homes, as coordination leverages the allowed 0.5°C under setpoint to minimise maximum power. In reality, 0.5°C below the setpoint is likely insufficient to be perceived as 'discomfort' for householders.

Table 15: Average thermal discomfort (degree-hours below setpoint) averaged across homes under different control strategies

Scenario	Standard controls	Standard controls + 2h switch off	Standard controls + 6h switch off	Passiv coordination
BNZ 2035	0.03	2.03	8.57	0.41
BNZ 2050	0.04	2.09	9.04	0.88

Conclusion

Passiv has calculated the additional electrical demand from installing low-carbon heating systems in two communities in the 2035 and 2050 uptake scenarios. They used 20 archetypes for each community and simulated every half hour of the year (in a typical and cold year). They also analysed the impact of a cold spell on total load in the community and evaluated various peak load mitigation strategies:

Where a 'switch off' command is issued, it needs to be for a sustained duration to completely avoid the EV peak. However, this will cause discomfort to homeowners the following day. Passiv optimisation and coordination can flatten or adjust demand as the energy centre requires while ensuring no individual house is overly cold.

5 Summary and next steps

Beyond the Alpha phase of the REACH project.

This final section summarises the findings from the Alpha phase of the REACH project and explores pathways for your continued community energy development.

The technical analysis indicates that while energy centres aren't necessary to address the identified network constraints, you can confidently proceed with low-carbon technologies, such as heat pumps and electric vehicles. This positive outcome means your community's journey toward net zero can continue with confidence. This is a particularly exciting time, as the current momentum in the sector presents numerous opportunities for communities like yours to get involved in clean energy initiatives.

While we work on our Beta phase application, we wanted to provide you with some practical pathways to continue advancing your energy goals. The suggestions after the summary of findings draw from successful community energy projects across the UK and reflect current opportunities in the rapidly evolving energy landscape. You may already be familiar with some of these approaches, but we hope they'll spark new possibilities and help build momentum for your community's energy transition.

Summary of findings

NGED

The network analysis for your community demonstrated that NGED's high-voltage network can accommodate the projected uptake of low-carbon technologies through 2030 under normal operating conditions. However, potential constraints emerge during abnormal fault conditions on Feeder 340040/0017.

During abnormal fault conditions, electricity demand consistently exceeded the network's capacity when power must be rerouted through a different Feeder (Feeder 340016/0015). This means there would be no spare electricity to charge an energy centre's batteries from the grid, forcing it to rely entirely on a generator. The resulting carbon emissions and logistical challenges of continuous fuel supply make an energy centre unsuitable for this location.

While this study identified constraints under abnormal fault conditions only, it is essential to note that it was conducted outside of NGED's Field Operations team and uses conservative demand assumptions for planning purposes. While there may be constraints in your area in the future, monitoring and addressing these constraints is part of NGED's core responsibility as your DNO. You should not be discouraged from proceeding with these low-carbon installations.

NGED's analysis also explored combining an energy centre with coordinated heat pump controls as a potential solution. However, the coordinated heat pump controls showed limited effectiveness because the community is relatively small compared to the total number of customers on the Feeder. The controls achieved only a 6.2% reduction in peak demand, reducing exceedance from 62.3% to 56.1%, which would not eliminate the constraint.

While an energy centre could theoretically resolve the network constraints by using generators to charge batteries that export power to the grid, the need for continuous generator operation makes this solution impractical from both environmental and operational perspectives. Therefore, an energy centre would not be required in this scenario. If the identified theoretical constraints materialised, NGED would likely deploy one or more mobile generator units in strategic locations to alleviate any constraints.

VEPOD

While it's unlikely that an energy centre would be deployed in your area, VEPOD tested whether an energy centre could address the identified network constraints during abnormal fault conditions. The study showed that Feeder 340040/0017 consistently exceeds its capacity by 62.3% during abnormal operation, meaning no spare network capacity is available to charge battery storage from the grid. A larger energy centre would be required to handle this constraint, i.e., an 833 kW diesel generator running continuously with 2 MWh of battery storage and 0.5 MW power conversion equipment.

VEPOD estimates that the total project costs would range from £620k for a basic setup to £1.35m for a premium installation. Continuous operation would also require approximately 4,692 litres of HVO fuel daily, which costs over £7,000 per day. VEPOD found that even combining the energy centre with coordinated heat pump controls would provide only modest improvements, reducing generator requirements from 833 kW to 795 kW.

While an energy centre is technically possible, the continuous generator operation requirement, associated carbon emissions, fuel logistics challenges and high operational costs make this approach impractical for this location. Conventional network reinforcement or mobile generator deployment (if ever necessary) would be more suitable solutions for your community than a permanent energy centre installation.

Passiv

Passiv found that the smart coordination of heat pumps across your community showed potential for managing peak electrical demand without compromising resident comfort, although with limited impact due to the smaller community size relative to the broader population served by the same Feeder.

In 2050 projected scenarios, coordinated control reduced peak demand by 29% (from 1,411 kW to 1,006 kW) compared to standard controls, flattening the demand profile while maintaining indoor temperatures within 0.5°C of target temperatures. The analysis also compared different demand reduction strategies and found that simple on/off approaches were less effective. For example, shorter 2-hour switch-offs created rebound peaks when systems turned back on, while extended 6-hour shutdowns caused temperatures to drop up to 2.57°C below target in the worst-affected homes.

The report also highlights the performance of different heating technologies. Technologies with thermal storage or hybrid configurations offered more flexibility, with hybrid systems providing the greatest potential for demand reduction without any comfort penalty.

Overall, the analysis revealed how community size affects the effectiveness of demand management strategies. As Bigbury is relatively small compared to all customers served by this part of the electricity network, coordinated heat pump controls achieved only a 6.2% reduction in peak demand in the broader network, reducing exceedance from 62.3% to 56.1%. This demonstrates that while the technology works well within the community, its impact on broader network constraints is limited when the community represents a small proportion of the total electricity demand.

As more homes adopt heat pumps, smart heat pump coordination may help manage some network constraints. However, the effectiveness depends significantly on the scale of deployment to the overall network demand. Further testing would be necessary to confirm these theoretical benefits in practice, particularly regarding the impact on household bills and the network-wide impact.

Conclusion

The good news is that NGED's analysis confirms your local electricity network can handle the projected uptake of heat pumps and electric vehicles through 2030 under normal operating conditions. Constraints were identified during abnormal fault conditions that would not be suitable to address with innovative solutions like energy centres or coordinated heat pump controls.

During rare fault conditions, when power must be rerouted through an alternative Feeder, the network on a particular Feeder in your community consistently exceeds acceptable limits. While coordinated heat pump controls showed promise within your community, achieving a 29% reduction in local peak demand, the relatively small size of Bigbury means this has a limited impact on the broader network constraints affecting your area. Similarly, an energy centre would require continuous generator operation, making it environmentally and operationally impractical.

Importantly, these findings should not discourage you from proceeding with low-carbon installations. The constraints identified occur only during abnormal fault conditions, and monitoring and addressing such constraints is part of NGED's core responsibility as your network operator. NGED will likely address these theoretical constraints through conventional network reinforcement or strategic deployment of mobile generator units rather than permanent installations if these constraints were to materialise.

You can proceed confidently with your heat pump installations and EV adoption, knowing that your network operator has viable solutions available to support your low-carbon transition.

What are our Beta application plans?

Over the next few months, we will develop our application for the Beta phase of the project. We aim to submit our funding application in October, although the scope may differ significantly from our original plans. While there's no guarantee of funding, we are working to address the lessons learned from this Alpha phase.

Unfortunately, both communities in our study were unlikely to need energy centres, which wasn't the outcome we had hoped for when we selected these locations. This means we need to fundamentally rethink our approach for any potential Beta phase, such as whether it will involve different community selection criteria.

As we work through these challenges and develop our proposal, we'll gain more clarity on what a revised Beta phase might look like. Your community's participation and the insights we've gathered will be crucial in helping us better identify suitable locations and solutions for future phases.

Potential next steps

To help with your next steps, we wanted to provide some potential pathways to continue developing your energy initiatives. We've compiled a set of resources that you may wish to use as suggestions in advancing your project goals. These suggestions draw from successful community energy projects and current opportunities in the sector. You may already be familiar with some of these ideas. Still, we hope they might spark new possibilities or approaches for your organisation and help build momentum for your community's energy transition.

General suggestions

- **Join your national community energy organisation** to get updates on what is happening in the sector and access knowledge-sharing opportunities and events.
    - Community Energy Wales
    - Community Energy England
- **Start or take part in an energy champion programme.** These programmes often offer access to workshops and training to help upskill a range of households in the community and support them to decarbonise their homes. These energy champions then act as key contacts who can advise the community and show how energy efficiency measures such as retrofit or low-carbon technologies work within different types of local properties, providing a trustworthy source of information. Examples and opportunities include:
    - Bristol Energy Network – Energy Champion
    - Low Carbon Hub – Oxfordshire – Energy Champion
    - National House Project – Young Energy Champions
    - Exeter Community Energy – Community Energy Champion
    - ACTion with communities in Cumbria – Energy Champions
- **Engage with other organisations encouraging community-centred retrofit or energy efficiency programmes**, such as People Powered Retrofit, a not-for-profit service based in Greater Manchester and the North West that offers a range of advice and services to support retrofitting of homes.
- **EV chargers:**
    - **Educational campaign** to inform local people interested in EVs on how they may be able to install an at-home charger.
    - **Community Charging**. Around 40-50% of drivers can't install a car charger at home for various reasons. Several programs and apps allow people to share at-home EV chargers with their neighbours. This allows people to register their home EV charger for others to book, use and pay for when they are not using it. This might suit people who have an empty driveway during the day or a driveway that could fit their car and another. Some examples of this include:
        - Co Charger
        - JustCharge
    - **Community-owned chargers**. ChargeMyStreet is an example of a social enterprise that installs and operates community EV chargers with money raised from

community shares and any profit reinvested into expanding the EV charging network. You can suggest chargepoint host sites through the ChargeMyStreet website.

  - **Explore and spread the word about government funding** for EV chargers for which people or businesses in your community may be eligible. This includes:
    - EV chargepoint and infrastructure grants for landlords
    - EV infrastructure grant for staff and fleets
    - Workplace Charging Scheme for state-funded education institutions
    - EV chargepoint grant for households with on-street parking
    - EV chargepoint grant for renters and flat owners
    - Workplace Charging Scheme
    - There is also guidance for installers of EV chargepoint infrastructure to help customers access grants.
    - Check if your Local Authority has applied for or is eligible for Local Electric Vehicle Infrastructure (LEVI) funding
    - You can also browse other relevant government-funded grants on their website.
- **Heat Pumps**
  - **Explore an education campaign** to inform local people about what homes are suitable for heat pumps, myth-bust any concerns and inform people about any grants and funding that might be available.
    - Consider how the physical space requirements and visual/noise impacts of heat pump installations might affect different members of your community. Information on this can often be found on heat pump installers' websites or from organisations such as the National Energy Foundation or the Energy Savings Trust. Be aware that additional considerations apply for listed buildings or properties in conservation areas, which may require special planning permission.

Government initiatives to watch

Several significant government initiatives are worth monitoring as you continue your community energy journey. These developments could provide new opportunities for funding, support and collaboration in the coming months:

Clean Power 2030, GB Energy and the Local Power Plan

The UK government has ambitious plans to deliver clean power by 2030, accelerating the transition from fossil fuels to a renewables-based energy system. By the end of the decade, the

UK government aims to have 95% of our energy come from the sun, wind and waves, balanced by storage, interconnectors and flexible energy demand.

To help enable this unprecedented growth in renewables, the UK government has also announced the establishment of **GB Energy** – a new publicly owned energy company designed to support investment in clean power projects. A cornerstone of GB Energy's strategy is the **Local Power Plan**, which aims to increase community and local authority participation in the energy system.

Within the Local Power Plan, the UK Government set a target to develop 8 GW of clean power through local and community-owned projects. The UK Government also pledged to provide support through £400 million annually in low-interest loans to communities and £600 million in grants to local authorities. In March, they provided an update on that funding (see below). The plan also promotes shared ownership models with private developers, giving communities a chance to have a meaningful stake in larger-scale projects (see our Sharing Power Paper, which provides recommendations to GB Energy).

While the full scope of GBE's activities is still emerging, several programs are taking shape:

- **Public Building Solar Initiative**: GBE's first major project will install rooftop solar panels on approximately 200 schools and 200 NHS sites, potentially establishing a model for similar community facilities.
- **Community Power Generation Fund**: £5 million in grant funding will be made available to town and parish councils, community organisations, sports teams, charities, and faith groups to support projects that help communities generate clean power.
- **Local Net Zero Hubs**: The government is providing £6.8 million to Local Net Zero Hubs across England. These hubs offer free services for local authorities to access the expertise and resources needed to launch clean energy projects, creating pathways for more community energy initiatives.

You can find a **recent update on GBE's plans here**.

The Great British Energy Act 2025 has now become law, formally establishing Great British Energy as an official government-owned energy company. The Act received Royal Assent on 15 May 2025, completing its passage through Parliament.

A significant development for community groups is that community energy was formally included via amendment within the GB Energy Bill with cross-party support. The sector view is that this amendment helps ensure that energy projects which benefit and involve local communities will be a core function of GB Energy, potentially opening new avenues for groups like yours.

Community Benefits and Shared Ownership Working Paper

In May 2025, the government published a significant working paper consulting on mandatory community benefits and shared ownership for low-carbon energy infrastructure. This consultation, open until July 16, 2025, seeks views on whether and how to implement these changes and has the potential to fundamentally change how communities benefit from energy projects in their areas.

Key proposals include:

- **Mandatory community benefits**: Requiring developers of renewable energy projects above 5MW (most commercial-scale projects) to provide community benefit funds (potentially £5,000 per MW annually or £2 per MWh generated)
- **Enhanced shared ownership**: The government may require developers to give communities the option for shared ownership in renewable projects built in their area, creating opportunities for residents to participate directly in the energy transition and earn returns from the clean energy infrastructure they host.
- **Cross-technology approach**: Creating uniform community benefit requirements for all low-carbon energy projects (wind, solar, nuclear, battery storage, etc.) across Great Britain.

Your community group should consider responding to the consultation to ensure your voices are heard in shaping these potential new requirements. We will be responding to this at Regen. Please share your thoughts with us!

Grid connections

After lobbying from Regen and others, the National Energy System Operator (NESO) introduced a CUSC code modification (CMP446) to help community energy projects connect to the grid more quickly. NESO proposed to raise the threshold for transmission impact assessment from 1 MW to 5 MW, which was approved by Ofgem on May 12, 2025 (see the decision here). This will allow community energy projects (typically smaller than 5 MW) to join the distribution network queue instead, speeding up the connection process.

Regional Energy Strategic Planners (RESPs)

RESPs will be delivered by NESO and will be introduced in 2025. They are being established to work with key local stakeholders, including local authorities and energy networks, to deliver regional plans that align with both local needs and national energy strategy. This new planning approach presents valuable opportunities for community energy groups to ensure your voices are heard, shape local energy priorities and strengthen the position of community-owned projects within broader regional energy strategies.

Staying in touch through Regen

These government initiatives reflect growing recognition of the vital role community energy plays in the transition to net zero. By staying informed about these developments, your community can position itself to benefit from new opportunities as they emerge.

At Regen, we often publish insights and hold events that might be relevant to your community energy organisation. To stay updated on our work and upcoming opportunities, we encourage you to visit our events page and our communities page, and sign up for our emailed newsletter, 'The Dispatch', at the bottom of our insights page.

Additional resources

Heat Pump overview and explanation: https://energysavingtrust.org.uk/advice/in-depth-guide-to-heat-pumps/

Heat pump myth-busting fact checker: https://www.homeenergyscotland.org/11-heat-pump-myths

General information from the UK Government about heat networks: https://www.gov.uk/government/collections/heat-networks

EV charger overview and explanation: https://energysavingtrust.org.uk/advice/charging-electric-vehicles/

NGED EV capacity map: https://www.nationalgrid.co.uk/smarter-networks/electric-vehicles/ev-capacity-map/

NGED network capacity map: https://www.nationalgrid.co.uk/network-opportunity-map/

6 Appendix 1 - REACH energy centre

Additional information on the REACH energy centre.

The proposed REACH Energy Centre is a hybrid unit containing both an HVO-powered genset and a Battery Energy Storage System (BESS) centrally managed by the smart VEPSystem control module.

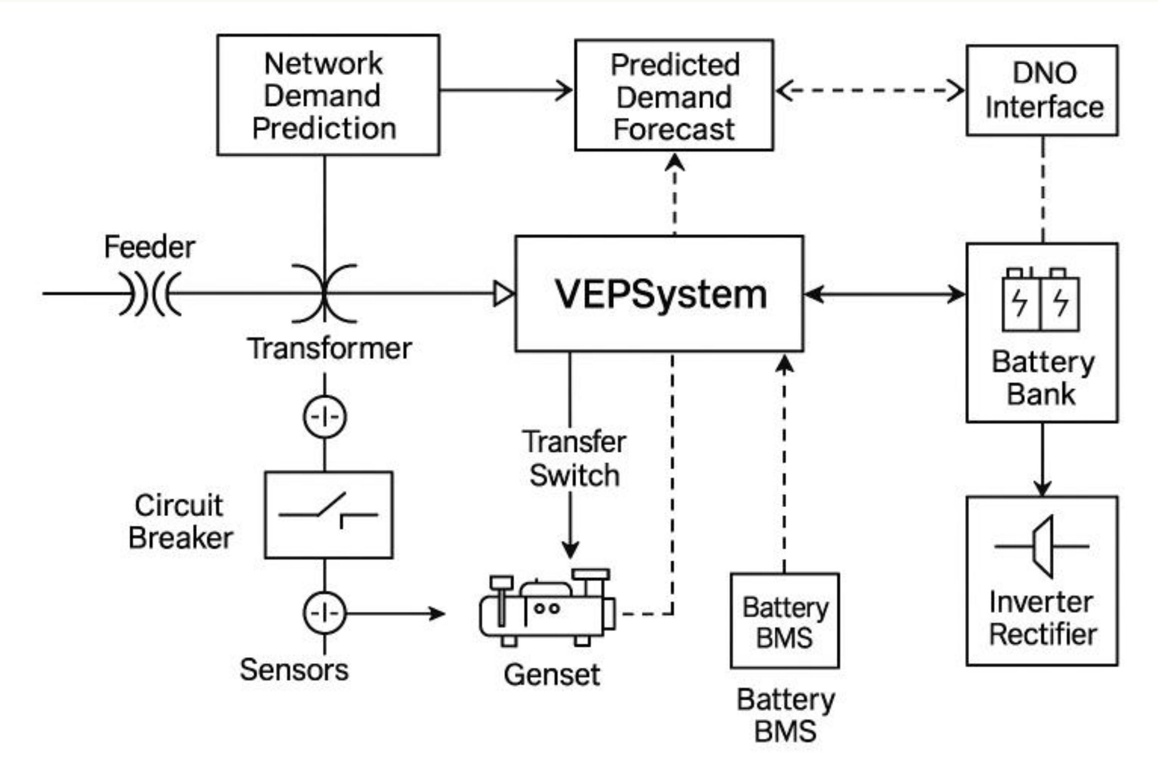


Figure 26: Schematic of REACH energy centre

1. Grid and protection

Feeder Line
The NGED distribution Feeder .

Transformer
Steps down medium-voltage power to the LV network feeding the REACH energy centre.

CT/PT Sensors
Current transformers (CTs) and potential transformers (PTs) provide voltage, current, and power measurements to the protection relay and VEPSystem.

Circuit Breaker
A rapid-trip device that can isolate the entire REACH centre from the grid under faults or maintenance.

2. VEPSystem (smart control system)

Core Brain
High-performance industrial controller (Programmable Logic Controller (PLC) / Remote Terminal Unit (RTU)) with embedded forecasting and optimisation. A PLC is a type of industrial digital computer that is programmed to control machinery. It performs tasks based on predefined conditions and inputs. An RTU is a microcontroller-based device used for remote monitoring and controlling field devices in industrial automation, particularly within Supervisory Control and Data Acquisition (SCADA) systems. SCADA is a computer-based system for gathering and analysing real-time data to monitor and control equipment that deals with critical and time-sensitive materials or events.

Inputs

- Real-time CT/PT measurements
- Predicted Demand Forecast (cloud service feed)
- DNO commands (Supervisory Control and Data Acquisition (SCADA) link).
- Battery State of Charge (SoC) & health from Battery Management System (BMS).

Outputs

- Genset start/stop & power setpoint
- Transfer-switch control
- Inverter/rectifier charge/discharge setpoints
- Alarms and status to DNO SCADA

3. Genset and transfer gear

Genset

HVO engine + alternator.

Transfer Switch

Solid-state or mechanical switch that connects/disconnects the genset to the LV bus.

Genset Controller

Manages engine speed, Automatic Voltage Regulator (AVR), and safety interlocks; accepts setpoints from VEPSystem.

4. Battery Energy Storage System (BESS)

Battery Modules

Lithium-ion racks.

Battery Management System (BMS)

Monitors individual cell voltages, temperatures, State of Charge (SoC), and State of Health (SoH); enforces safe operating limits.

Communication

BMS ↔ VEPSystem for SoC updates and health status.

5. Inverter / rectifier

Bidirectional Power Converter

- Rectifier Mode: draws excess genset or generator export to charge the battery at up to rated current.
- Inverter Mode: injects battery power back onto the LV bus to shave peaks.

Control Interface

Receives charge/discharge commands from VEPSystem; reports operating status and alarms.

6. Network demand prediction

A cloud-based forecasting engine that uses Artificial Intelligence (AI) / Machine Learning (ML) to predict half-hourly Feeder load up to several hours ahead.

Feeds a Predicted Demand Forecast to VEPSystem for pre-emptive asset dispatch.

7. DNO interface

Supervisory Control and Data Acquisition (SCADA) / Human-Machine Interface (HMI) Gateway, where HMI is the user interface that allows operators to interact with machines and systems, providing a visual representation of data and controls.

Allows the Distribution Network Operator to:

- Monitor real-time flows, SoC, and genset status.
- Issue remote commands or curtailment instructions.
- Receive alarms and performance reports.

Operation workflow

1. **Data Acquisition**
    - CT/PT sensors and BMS streams feed VEPSystem.
    - Forecast engine sends predicted demand profile.
2. **Decision & Scheduling**
    - VEPSystem calculates:
        - When to pre-start genset based on forecast.
        - How to split load between genset and battery.
        - Charging windows to restore SoC.
3. **Dispatch**
    - VEPSystem closes transfer switch, starts genset, sets its power to the continuous setpoint (e.g. 250 kW).
    - For any export above that, commands inverter to discharge from the Battery Energy Storage System (BESS).
    - For export below that, commands inverter to charge BESS at available headroom.
4. **DNO Coordination**
    - If the DNO issues a command (e.g. reduce local injection), VEPSystem adjusts setpoints accordingly.

5. **Protection & Fault Response**
    - On any grid fault or overcurrent, the breaker trips, VEPSystem gracefully shuts down assets, and notifies DNO.

This detailed layout ensures robust, forecast-driven control of local generation and storage, seamless DNO integration, and full protection for reliable Feeder support. The REACH energy centre is thus well placed to ensure accelerated low-carbon technology adoption in rural areas whilst maintaining the stability of the network.

7 Appendix 2 – VEPOD genset fuel

Additional information on the cost of VEPOD genset fuel

Fuel consumption for HVO-powered gensets typically ranges from **0.21 to 0.25 litres per kWh** at full load. We'll use a typical value of **0.23 litres per kWh** for HVO, which aligns with manufacturer data. We will further assume that 1 litre of HVO costs £1.50 for illustrative purposes:

BNZ 850 kw genset running continuously over a 24-hour period

Daily Energy Output:

850 kW×24 hours=20,400 kWh

Fuel Consumption:

20,400 kWh×0.23 litres/kWh=4,692 litres of HVO

Fuel Cost

4,692 litres×£1.50=£7,038

Summary:

HVO Fuel Consumed: ~4,692 litres over 24 hours

Fuel Cost @ £1.50/litre: £7,038

8 Appendix 3 – Passiv UK on decarbonising heat

Additional information from Passiv UK on decarbonising heat.

Passiv is a UK-based smart energy technology business with over a decade of experience developing software solutions for home decarbonisation. The company believes that accelerating the journey to net zero and reducing the cost of low-carbon technologies will require making them more efficient and connected to a broader, more flexible energy system. Since its foundation in 2009, Passiv has designed and delivered numerous innovation initiatives, developing pioneering solutions that have provided valuable insights into the energy transition.

Passiv's core focus is on remote monitoring and predictive heating management technology using patented, machine-learning thermal modelling algorithms. The company works with a range of industry partners, including energy suppliers, distribution networks, technology providers, consultancies and academia, and supports ongoing PhD placements with leading UK universities. Global manufacturers, housing developers, and supplier partners are now choosing Passiv to deliver their net-zero smart home heating solutions.

Background to Decarbonisation of Heat

Heating is fundamental to daily life, impacting comfort, convenience, health and well-being. Home heating accounts for approximately 18% of national emissions in the UK, significantly contributing to the climate crisis. Over 90% of UK homes rely on fossil fuels like gas and oil for heating. Achieving net-zero emissions by 2050 will require a transformation in how homes are heated.

Electrification Pathway

Electrification is widely considered the most commercially viable option for decarbonising UK heating, especially as the electricity sector transitions to renewables. This pathway involves replacing fossil-fuel heating systems with electric systems, such as heat pumps, which produce no direct on-site emissions. As the power sector decarbonises, emissions from these electric heat sources will decrease further.

Heat pumps, particularly air-source heat pumps (ASHPs) and ground-source heat pumps (GSHPs), are central to the electrification pathway. They extract low-grade heat from the environment (air, water, or ground) and convert it into usable warmth. This process is highly efficient. For example, an ASHP typically produces at least 2.5 units of heat for every unit of electricity consumed, while a GSHP can achieve a slightly higher ratio. ASHPs are typically more affordable and easier to install, while GSHPs require more space and involve a higher initial investment, but provide better long-term efficiency.

Thermal storage is another key feature of the electrification pathway to decarbonisation. This approach stores thermal energy using heat batteries, hot water tanks and the fabric of buildings themselves. With the right controls, stored heat (thermal inertia) can be released during peak demand or high-price periods or recharged during periods of high renewable generation and low electricity prices, improving whole-system efficiency and reducing the strain on the grid.

Smart Controls

Traditional heating controls often don't work as well with heat pumps. Most conventional thermostat options used on existing heat pump installations were designed for either gas boilers or air conditioning units. These systems can lead to heat pumps failing to meet room setpoints, running at high flow temperatures, and cycling on and off, causing inefficiencies, high heating bills, and negative perceptions of the new heating system. They often also lack the connectivity to allow control via smartphone or be futureproof against uptake of time-of-use (ToU) tariffs and flexibility opportunities.

The UK's ageing housing stock poses challenges for heat pump installations, with over a third of homes built before WWII and many lacking modern energy efficiency measures. Homeowners are also accustomed to gas or oil systems, which operate at high flow temperatures and respond quickly to temperature changes and heating demands. While heat pumps can exceed 300% efficiency, compared to around 85% for modern gas boilers, their performance is driven by factors like flow temperature. Heat pumps transfer heat rather than generate it, and the lower the flow temperature, the more efficiently they can operate, requiring less energy to move heat into the home. Lower flow temperatures improve efficiency, but most installations use static flow settings, which do not adapt to real-time conditions or homeowner behaviour. Smart control systems address this by learning a home's heat retention and system response while integrating live weather data, optimising performance for greater efficiency and comfort.

Beyond the underlying building fabric efficiency and setup, ongoing heat pump running costs are highly dependent on electricity pricing. Time of Use tariffs allow consumers to pay variable rates based on supply and demand, offering savings by shifting electricity use to off-peak periods. In the UK, wholesale electricity prices fluctuate every half-hour, typically peaking in the evening and dropping overnight. While most households use flat-rate tariffs, modern smart meters enable more flexible pricing options, such as Octopus Agile and heat pump-specific plans like Octopus Cosy.

Strategic heat pump operation is key to maximising these savings. Heating demand often peaks during expensive periods, but homes act like thermal batteries, retaining warmth after heating. By preheating when electricity is cheaper, such as overnight, households can reduce reliance on peak-hour pricing while maintaining comfort. For simple tariffs like Economy 7, users can manually adjust heating schedules. However, dynamic tariffs require automation. Smart control systems use real-time data to optimise heat pump operation based on electricity prices, weather conditions, and household habits. By leveraging these intelligent controls, heat pumps can run at the lowest possible cost while ensuring efficiency and comfort.

Passiv's Smart Thermostat (PST) is designed specifically for heat pumps, turning any heat pump into a smart, connected device that can follow dynamic ToU tariffs or provide flexibility to the energy system without compromising comfort. The PST simplifies heat pump operation, learns how a home heats and cools, and provides intuitive control via an in-home thermostat, programmer, or smartphone app. It can help to reduce heating bills using advanced machine learning to adjust flow temperatures and optimise for smart tariffs and solar PV. The PST also provides grid flexibility through automated demand-side response (DSR).

Energy Efficiency

Improving home energy efficiency is key to decarbonising heat. Insulation reduces heat loss in winter and heat gain in summer, lowering energy demand and consumption. The 'fabric first' approach prioritises building insulation before upgrading heating systems, but rapid decarbonisation challenges this assumption. While insulation reduces demand, decarbonising heat itself is crucial for achieving net zero.

Large-scale trials, such as the government's Electrification of Heat project, show most homes can transition to heat pumps without major fabric upgrades. Deep retrofits, like solid wall insulation, are costly and disruptive, making large-scale implementation challenging. However, low-cost measures like draught proofing and insulating cavity walls and lofts remain beneficial.

Heat pumps work best at lower flow temperatures, with efficiency influenced by radiator size, system design and smart control systems. As the electricity grid decarbonises, electric heating's carbon footprint will decrease. Energy reforms like the introduction of Market-wide Half-Hourly Settlement (MHHS), which will support more time-of-use tariffs and demand-side-response (DSR) schemes that reward flexible power consumption such as the Demand Flexibility Service (DFS), will also impact ongoing running costs.

Decarbonisation strategies should balance insulation with heat system upgrades, considering costs and long-term benefits. Fabric improvements enhance comfort, reduce damp and improve heat pump efficiency. However, achieving net-zero heating at scale will require prioritising heat pumps and clean energy solutions alongside targeted insulation improvements.

Case Study: Clean Heat Streets

The Clean Heat Streets project aimed to accelerate heat pump adoption through a community-focused approach. Led by Samsung in collaboration with various partners, including Passiv, the project addressed barriers to heat pump uptake.

The project comprised two phases: a feasibility study and community engagement/installation. The feasibility study in Rose Hill, Oxford, developed a local area energy mapping approach and identified key obstacles to heat pump adoption. The second phase involved installing heat pumps in six 'show home' in the community to demonstrate their benefits to neighbours.

Clean Heat Streets fostered community involvement, leveraged dynamic tariffs and smart controls, and collaborated with the local DNO (SSEN) to address network constraints. By reducing upfront and operational costs, the project demonstrated the potential of a community-focused approach to enhance low-carbon heating adoption. The project is now aiming to install 150 heat pumps across these substation areas.

Heat Networks Pathway

Heat networks distribute heat from a central source to multiple buildings, which is particularly effective in dense urban areas or industrial clusters but can be employed in many areas. They enable the use of large-scale, low-carbon energy sources, such as industrial waste heat or large heat pumps, which individual homes cannot access. Heat networks are also flexible, allowing the integration of newer low-carbon technologies.

Case Study: Swaffham Prior's Rural Heat Network

Swaffham Prior, a village in East Cambridgeshire, is pioneering the UK's first rural heat network. The project aims to provide 100% of the village's thermal energy demand using renewable sources. The network uses a combination of air source and ground source heat pumps, providing heat to homes and community buildings. The project has secured significant funding but faces ongoing challenges related to customer uptake.

Heat networks typically rely on a large commercial anchor heat load, such as a hospital, as a reliable, stable demand. In rural areas, achieving sufficient customer density for financial sustainability is a significant challenge. While ambitious, Swaffham Prior's heat network has struggled with low household participation (20% as of early 2024), impacting its financial viability. Original feasibility studies suggested 70% uptake would be needed to achieve long-term financial viability. There are concerns about cost competitiveness compared to individual heat pumps, as charges continue to be benchmarked against heating oil. Achieving the necessary uptake may require significant financial incentives, potentially reducing returns on investment. Even with full participation, the decarbonisation cost per property is substantial, raising questions about affordability and scalability.

While rural heat networks like Swaffham Prior's present challenges, they offer critical insights into the complexities of community-led decarbonisation. For communities facing uncertainty about large-scale network implementation, alternative technologies such as smart thermostats may provide a more flexible pathway to reducing energy consumption. Passiv's Smart Thermostat, for instance, demonstrates how intelligent control systems can transform existing heating infrastructure, offering grid flexibility and potential cost savings without requiring comprehensive network-wide changes. Regardless of their immediate success, these pioneering efforts provide essential learnings about community engagement, technological adaptation, and financial modelling. The challenges encountered are not insurmountable barriers, but rather important milestones in understanding how to effectively scale renewable heating solutions. As the UK continues to pursue its net-zero goals, these early-stage projects play a crucial role in developing more refined, adaptable, and community-centred approaches to rural energy transformation.

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