The ACCESS Project: 'Assisting Communities to Connect to Electric Sustainable Sources'

Final Report prepared for Local Energy Scotland

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Acronyms

acronym	term	explanation
AD	Anaerobic Digestion	A controlled decomposition mechanism whereby organic matter is broken down by bacteria in the absence of air to produce methane, hydrogen and other compounds.
ANM	Active Network Management	Control methodology to adjust loads and generation on a near-real-time basis to keep various network parameters within defined ranges.
AS	Ancillary Services	Contracts issued by National Grid to help them to balance the grid.
BM	Balancing Mechanism	The means used by National Grid as the ESO to buy additional capacity or reductions to keep the system within limits
CARES	Community and Renewable Energy Scheme	The Scottish Government's support scheme for community and locally-owned RE initiatives
CES	Community Energy Scotland	Scotland's community energy charity, a member organisation representing 400 community groups
CCGT	Closed-Cycle Gas Turbines	The most efficient type of engine to convert natural gas to rotary motion and hence to an electrical generator
DLC	Direct Load Control	A mechanism for an entity to directly control a load by switching it remotely
DN	Distribution Network	The lower-voltage segments of the electricity network below 132kV (in Scotland)
DNO	Distribution Network Operator	The organisation responsible for the installation and upkeep of the distribution network
DSM	Demand-Side Management	A system to control loads in a predetermined way Sometimes used to denote DSR
DSO	Distribution system operator	The entity responsible for the DN
DSR	Demand Side Response	A system to control loads in response to an external signal or trigger
DTU	Demand Turn-Up	Increasing a load in response to a request
DUoS	Distribution Use of System	Payments to cover the cost of maintaining the DN
ESO	Electricity System Operator	The new name for NG's role in managing power flows at national level also referred to as SO
FFR	Firm Frequency Response	A fast-reaction Ancillary Service used by the ESO to correct power balance on the grid
FiT	Feed-in Tariff	Government support payments to encourage small-scale renewable energy generators
FPN	Final Physical Notification	The amount of power contracted 'gate closure'—part of the BM system
FR	Frequency Response	An Ancillary Service used by the ESO to correct power balance on the grid
LCOE	Levelised Cost of Electricity	A means of combining capital and running costs of generating electricity into a single figure for the sake of comparing different generators

MICT	Mull and Iona Community Trust	The community organisation that owns and runs Garmony Hydro
MID	Market Index Data	An average electricity price calculated by Elexon for each half-hour settlement period
NG	National Grid	The organisation that functions as Electricity System Operator and runs the Balancing Mechanism
NHH	Non-half Hourly	This is the standard type of electricity metering used in most homes without consumption being recorded for each 30-minute period of the day
NIA	Network Innovation Allowance	Funding mechanism for DNO innovation projects
PPA	Power Purchase Agreement	The contract between a generator and another party regarding the sale of generated electricity
PV	Photo-Voltaic	Solar' panels that turn light into electricity
RE	Renewable Energy or Electricity	Electricity (or other forms of energy) generated from non-fuel-based systems, ie, from resources that are naturally replenished and cannot be readily depleted, eg, sunlight, wind, water
SHCS	Scottish Housing Condition Survey	Annual survey of homes in Scotland, collecting data on physical condition and householder experience
SMETS	Smart Metering Equipment Technical Standard	The technical requirements for smart meters in UK
SNH	Scottish Natural Heritage	Scottish public body responsible for the country's natural heritage, especially its natural, genetic and scenic diversity
SO	System Operator	NG's role as system balancer, now called ESO
SOTN	State Of The Network	The supervisory control system for the Cranix loads and generator
SSEN	Scottish and Southern Energy	A vertically integrated organisation providing electricity services
SSEN	SSE Networks	The DNO for northern Scotland
THTC	Total Heating Total Control	SSE's remotely controlled off-peak tariff
TSO	Transmission System Operator	National Grid's role as manager of the higher voltage assets in GB
TUoS	Transmission Use of System	Payments to cover the cost of maintaining the transmission network
UoS	Use of System	Various payments to cover the cost of operating assets for the benefit of users
VSCon	VCharge System Controller	The VCharge communications module that interfaces with on-site equipment at Garmony and Lochdonhead and conveys data between various parts of the system.

1. Executive Summary

CONCEPT

The ACCESS (Assisting Communities to Connect to Electric Sustainable Sources) Project is an example of what can be achieved through local ambition, creativity and collaboration all in the unwavering pursuit of long-term environmental, social and economic sustainability. Long-gone are the (relatively) easier days of traditional grant-funded community projects serving the needs of local activity through feed-in-tariffs or subsidies and in the face of UK-wide cuts to these traditional funding mechanisms, communities must engage in increasingly complex solutions which are locally relevant and financially sustainable. Never before has it been so crucial for unfamiliar partners to come together to formulate and realise solutions which both challenge our current energy system while proving interim and long-term alternatives which are renewably-powered and locally relevant.

Thanks to project funding from the Scottish Government and Ofgem's *Network Innovation Allowance,* the ACCESS Project has successfully demonstrated one such solution in the form of a real-world 'flexible-connection' offer for local renewable generators. These types of flexible connections are especially important in areas where the electricity grid is already at full capacity (ie, it cannot take any new electricity generation) or where the network wires are in need of expensive upgrades or replacements. The flexible connection concept and technology proven by ACCESS circumvents both of these issues to ultimately maximise the number of community renewable energy projects across Scotland and beyond. This in turn reduces the amount of greenhouse gasses associated with our energy needs while retaining local value in local economies.

DESIGN AND TESTING

So what exactly did the project do? In very practical terms, domestic heaters of various types were fitted with remote-control units so that a cloud-based 'brain' could trigger them to switch on or off in real-time to match the local hydro scheme's generation output. Controls were also installed at the hydro station, establishing communications with the central 'brain' and enabling generator output to be controlled remotely. This constituted a second, failsafe line of control for mitigation of grid constraints, should switching of the domestic heaters prove insufficient. Importantly, comfort levels in the participants' homes were still set by the participants so they remained in control of their heating requirements. Over the course of the project, the ACCESS system was designed, tested at the PNDC, installed and tested again in-situ on the Isle of Mull. Proving this particular flexible connection concept and demonstrating that local loads can be switched on and off remotely to match the power output of a hydro-electric generator constituted a significant achievement for the project. Crucially, it also showed that the electricity network power flows can be monitored and that the domestic heating loads and hydro scheme output could be adjusted to keep within set limits for the network while maximising the output from the community hydro scheme.

OUTCOMES

In short, the outputs from this project provide the evidence for DNOs to be confident that this solution works and is sufficiently robust to deploy in real-world, constrained situations without risk to the network. Participation in the project was key in the decision of the network operator, SSEN, to offer a new 'flexible connection' option to constrained generators, as described by SSEN's Frank Clifton:

"SSEN were incredibly proud to be part of the Mull ACCESS Project which, through the hard work of the project team and such great community ambition, helped enable SSEN to establish new flexible connection options which are now available to customers. These new options allow generation customers to connect more quickly in areas which are currently constrained by utilising the existing network more flexibly, "

The benefits of this type of local energy solution are manifold; improving the efficiency of the local network, reducing losses in wires and transformers and increasing the resilience of the electricity system as a whole. Financial benefits are also achieved due to increased output, especially where a generator is constrained by network capacity, while the project also highlighted value to be gleaned via financial mechanisms such as local domestic supply tariffs that reward householders for offering flexibility in relation to their various heating demands loads to the system.

COMMUNITY

A fundamental part of the project was the participant engagement and awareness-raising activity that was carried out to ensure that all of the participants had a sound understanding of the purpose and benefits of the Project in relation to their own community and wider applications. It also meant that any practical problems or concerns were quickly and thoroughly addressed via a formal customer care process. Participant 'buy-in' to the project's aims and intended outcomes remained very high throughout the project and participants also received annual participation payments. Satisfaction levels throughout testing have also been good with learning points constantly being incorporated into delivery. The project assessed the commercial arrangements required for future deployment and rollout via 'local energy tariffs' and increasing local engagement and awareness of the transitioning energy sector to local end-users so that they better understand—and therefore benefit from—the potential financial savings available to them and their communities. In this regard, the ACCESS Project supports local and national economic development by creating new markets for locally generated electricity in grid-constrained areas.

On behalf of the project consortium, I thoroughly hope you enjoy reading through this report and that it might aid and inspire others to create and deliver their own locally tailored local energy economy solution.

Gillian Hurding
Innovation Manager and ACCESS Project Manager
Community Energy Scotland, 2018.

2. Project Overview—Mull and the ACCESS Project

a. *The Islands of Mull and Iona*

Figure 1 Overview map showing location of Mull and Iona

Mull and Iona are Inner Hebridean islands located close to the West Coast of Scotland, forming part of the Argyll & Bute council area. Mull has a population of around 2900 people, while Iona, which is separated from the Mull by the one-mile-wide Sound of Iona, is home to approximately 130 residents. Both islands are separated from the Scottish mainland by the Sound of Mull and the Firth of Lorne. Mull is the fourth-largest Scottish Island, covering almost 340 square miles, while Iona represents just 1% of Mull's landmass.

Tourism is the largest sector in Mull and Iona's economy, having overtaken farming, fishing and forestry in recent years. Ecotourism in particular has grown considerably since the 1990s. The reintroduction of white-tailed eagles to Mull in 2005 has generated up to £5 million in tourism income every year, supporting up to 110 jobs on the island. Other notable incomes for Mull include the Tobermory whisky distillery, Isle of Mull cheddar and local fish. Iona remains a popular tourist destination due to its historical and religious importance and notably, Iona Abbey.

The main settlement on Mull is Tobermory, located on the north-eastern side of the island, with the majority of the remaining population on Mull located around the coastline due to the centre of the island being mountainous. Much of the population is spread out across the island in many small villages. The main transport to Mull from the mainland is by ferry from Oban, while a second ferry links to Iona from Fionnphort at the western point of the Ross of Mull.

b. *Local Generation on Mull: The Garmony Hydro Scheme*

Figure 2 Satellite image of Mull with sub-seaconnectors and important locations shown

Mull is connected to the Scottish mainland by a 33kV subsea cable (shown in green in Figure 2) across the Sound of Mull but the majority of the island's electricity arrives at Lochdonhead substation via 33 kV subsea cables across the Firth of Lorne from Tulloch switching station near Oban on the mainland. Mull imports between 1 and 8 MW of electricity depending on time of day and season of the year.

Garmony Hydro is a 400kW run of river hydro scheme owned by Green Energy Mull on behalf of the Mull and Iona Community Trust at Garmony. Garmony is situated on the eastern side of the Isle of Mull. Mull and Iona Community Trust (MICT) secured funding from the Scottish Government's Community and Renewable Energy Scheme (CARES) to develop a hydro site on Mull, with Garmony the preferred location following a feasibility study. It is estimated that the Garmony hydro scheme should generate over 1 GWh of power each year or about 3½% of the island's consumption.

3. Introduction and Project Summary

This report provides an overview of progress during the ACCESS Project's delivery phase, highlighting key learning. It also outlines the project's relevance to all of those interested in distributed renewable energy generation. More detailed information on the project can be requested from the lead partner, Community Energy Scotland:

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a. *Background*

Community Energy Scotland (CES) works with community groups across Scotland, many of which want to install renewable energy electricity generators for the sake of reducing greenhouse gasses and supplying the community's own energy needs. CES**,** therefore, have a charitable remit to empower local communities by helping them to own, control and benefit from their local renewable energy resources, control and reduce their energy costs, regenerate their communities and play their part in the low carbon transition.

b. *The problem*

An increasing number of renewable energy (RE) installations cannot easily connect to the electricity grid because of 'constraints' on the grid that limit the amount on new generation that can be accepted. That is to say, at peak times, the grid is essentially too full of electricity to handle any more electricity produced by renewable technologies. For more detail please see Section 4 of this report. Many RE projects are therefore not able to progress and communities are losing out.

There is currently no local energy tariff being offered by energy suppliers to support commercial solutions to this problem. Equally, few community groups are aware that there are issues like this with the electricity grid and most householders do not have any exposure to the complexities involved with generating and supplying electrical power and therefore lack in understanding of the issues and opportunities presented by local, renewable energy solutions.

c. *A potential solution*

If, however, instead of being exported onto the grid and transmitted further afield, the local renewable electricity can be distributed locally, the grid could continue to operate within its statutory voltage limits and margins of safety and still allow new generation to be built and connected. In short, a solution which allows real-time matching of local generation with local loads is required to keep things balanced and renewable technologies generating without imposed constraints. The controlled loads would have to be monitored and controlled so that it is clear that energy is flowing as expected and the network would have to be monitored to ensure that voltages and power flows remain within the right levels. For this project, the controlled loads were storage heaters, flow boiler and hot water cylinders but any controllable load can be used with this method including electric vehicle chargers or energy storage systems.

To be commercially sustainable, any such local balancing needs to be achieved through a financial mechanism that rewards participants for their contribution to the solution. This is best achieved by a local tariff that links the generator and consumer participants in a mutually beneficial arrangement. This engages the community and its individual households in a tangible and uncomplicated solution that they can easily take part in and benefit from.

d. *Testing a solution*

Although the idea of balancing sounds straightforward, the electricity network is sufficiently complex that it is generally not easy to test this type of solution in most situations. Too many interactions with different, uncontrolled and unmeasured power flows mean that actually 'seeing' what is happening becomes difficult. By finding a part of the network that is less interconnected, and therefore easier to monitor, it becomes possible to test this approach and verify that power flows change as expected. The Islands of Mull and Iona provide just such a situation and the community-owned generator at Garmony is an ideal source of power to 'match' local heating demand against.

As alluded to above, full testing of a solution needs to consider the associated business model including legal arrangements with local generators and energy tariff options for local consumers so that any technical solution can be replicated in other areas. In the context of a 'test' project, it is possible to use a commercial 'work-around' to investigate commercial options and make best practice recommendations to inform policy and regulation.

e. *The approach*

With the Garmony Hydro generator in place and producing power on the island of Mull, the next step was to create a new aggregated electric load or 'demand'. This was done by recruiting approximately 75 households across Mull and Iona and modifying or replacing their existing heating and/or hot water appliances. To test various scenarios, some householders were given new electric storage heaters, each fitted with smart controls called 'Dynamos' while other participants, with slightly newer existing heaters, had the smart Dynamo switches fitted to their existing heaters. The same approach was taken to the householder's hot water demand: those who needed replacement hot water cylinders (HWC) were provided with new ones which had a Dynamo switch attached while others had retrofit Dynamos attached to their existing HWCs. The Dynamo switches all linked back to a central control system that not only monitors when the heaters and HWCs are switched on and storing heat but could also control when the devices were turned on and off.

The Garmony Hydro generator was also fitted with extra equipment to communicate back to this central control system while network monitors were used to monitor the main electricity connection from the mainland to the island and measure the amount of power imported onto Mull.

The central control system was then configured to run various tests and record the results.

Various business models have been analysed (see section 6.f) and different tariff options considered (section 6.g.iii.). These show that energy suppliers can create local tariffs to maximise the benefit of such a demand-side response system to alleviate constraint on a generator. Smart metering and half-hourly (HH) settlement are instrumental in these mechanisms and the smart meter roll-out and domestic HH settlement will make this approach straightforward.

During the community engagement events used to recruit participating households, the local energy agenda was stressed and explained as well as the technical aspects of the project. It is clear that the idea of using locally generated electricity locally makes sense to people and they can be sufficiently supportive that they are willing not only to sign up to a local solution, but to actively participate in trials like ACCESS to help make this transition happen. Key to this local support is the presence of strong local community anchor organisations (in this case, the Mull and Iona Community Trust), national or regional co-ordinating/enabling organisations (Community Energy Scotland), and community owned generation.

f. *Desired outcomes*

With the above in mind, the ACCESS project was designed to test and subsequently prove that local energy matching is possible. It did this in line with the requirements of the network operators by firstly showing that ‘trigger events’ from network measurement points could be correctly interpreted and quickly responded to so that the network remained balanced within the required island import limits.

The project also set out to show how local energy generation could be maximised to make use of local, community-owned renewables by bringing on local demand from local households in real-time. In this aim, the project was keen to investigate how easy it might be to match the output from the hydro scheme generally but also in response to live network ‘trigger events’.

Understanding that householder ‘buy-in’ is a vital component to successful local energy solutions, the project also wanted to show the benefits of involving an active local community partner and a mechanism for maintaining accurate, responsive and relevant ‘customer’ support for a business-as-usual replication.

The final part of the project was to develop a business model and rebate mechanism such that a curtailed generator can be ‘unleashed’ by local loads in such a way that the financial advantage can be apportioned between the generator and involved households to the benefit of all partaking in the local energy scheme. While fully establishing such a mechanism was deemed out with the scope of this project, a thorough investigation of potential business models was desirable and therefore investigated and informed by the project. (See 6.f)

g. ***Proving the ACCESS communication concept***

All of the network tests concluded successfully, demonstrating the desired outcomes. By the end of the project, the domestic heating load could be set to (i) to prevent the island import, measured at Lochdonhead, from falling further than an arbitrarily set threshold level follow the available generation within certain operational constraints and (ii) follow the available generation within certain operational constraints. In short, the heaters and hot water cylinders or ‘heating assets’ charged up in response to signals from the project’s communication system, absorbing the hydro scheme generation within the island, while still delivering the comfort level set by the house occupants.

All network safety checks ran as expected with the hydro generator defaulting to a safe set-point in the event of loss of communications. The load controllers at Garmony defaulted to ‘business as usual’ settings if no signal was received to instruct a different behaviour. The heaters and hot water cylinders also went into a standalone or ‘home alone’ mode, charging up at their usual standard tariff times if they lost communications with the central control system.

h. ***The results***

The outputs of these tests indicate that the ACCESS communication system is robust, stable and responsive, and provides useful grid services; namely real-time electricity balancing and potential for curtailment mitigation. The system provides a safe mechanism for connecting additional distributed generation in areas where the grid is deemed to be ‘saturated’ or ‘constrained’ due to congestion at higher voltage levels. Network safety is maintained and improved due to tighter regulation of power flows. The methodology provides a route towards the electrification of domestic heating which is a significant, current challenge.

SSEN has been very supportive of the ACCESS project and enabled it by providing access to their equipment for installation of line monitors and such. They have been clear in their recognition of the successful outcomes of the project and the validation of this mechanism to avoid constraints. They are looking at ways to incorporate this technique into ‘business as usual’ so that they can offer this solution to other renewable energy generators that would otherwise struggle to connect to the grid, and have created a 'flexible connections' offer to facilitate this sort of approach in future.

Four mechanisms are evaluated for possible commercial arrangements, viz, third-party aggregator, DSO, net-metering and DSR tariff. Each model has its own pros and cons but the latter two are seen as most beneficial. There are regulatory barriers to each of these and Ofgem is aware that changes are necessary to unleash the necessary flexibility on the network.

i. ***What next?***

Having successfully proven the ACCESS communication system in this less-complex, real-world environment, the technology and methodology is ready for application in situations where community generators face real network constraint. For the Distribution Network Operators, this ACCESS model adds no significant risk and actually provides a self-correcting mechanism to stabilise remote parts of the grid. For community groups, it provides a practical and commercial methodology for implementing projects that have been scuppered by grid capacity issues and diminishing traditional financial support mechanisms such as the feed-in-tariffs. Electrification of Scotland's heating and other sectors like transport can be supported toward a low carbon transition by this technique.

As well as demonstrating the technical effectiveness of the solution, the analysis below identifies the potential for implementing this type of flexible connection and related community-benefit models elsewhere and quantifies the resultant carbon reduction. Lessons learnt from the customer engagement aspects and collaborative working are also useful in rolling out this solution in other places and more generally supporting the energy system's low carbon, smart, transition by raising community and end-user knowledge and experience of such schemes.

There is a possibility of another generator on Mull needing this arrangement to secure a full-capacity grid connection and the participants will be approached with a commercial offering if this goes ahead. Most of these customers now have over three years of involvement with this project.

The ACCESS solution will help in the decarbonisation of our energy networks by maximising renewable energy generation. It will also reduce the losses intrinsic in moving electricity along the connecting wires. It importantly provides a useful precedent and business-as-usual solution for the network operators which will become increasingly relevant as their role transitions toward that of *system* operators. SSEN are already offering flexible connections based on the precedent set in this project. Energy Networks Association is assessing mechanisms like this to effect the transition to a low-carbon, flexible grid.

j. ***Funding***

ACCESS was funded by the Scottish Government through its Local Energy Challenge Fund, 2015. The total project cost was about two and a half million pounds, with £1.8M in grant from the Scottish Government, £0.3M from Ofgem's Electricity Network Innovation Allowance (NIA) via SSE Networks and about £0.4M provided by the project partners as contributions in kind.

k. *Organisations involved*

The project partners during the Project's implementation phase were:

Community Energy Scotland	Lead partner, responsible for the overall project design and delivery, participant communications and co-ordination of work streams
Mull and Iona Community Trust (MICT)	Local organisation facilitating recruitment of participating properties and on-island point of contact/support with participant queries
SSE Energy Solutions Ltd	Oversaw domestic installations
SSE Energy Supply Ltd	Provides customer interface for project
VCharge UK Ltd	Provider of DSR equipment and infrastructure, oversaw domestic equipment removal
Element Energy Ltd	Analysis of future business models, results and implications
Plus project advisors:	
SSE Networks (SSEN)	DNO and advisor on network safety & efficiency
Glen Dimplex	Heating equipment provider, ad hoc support for participant enquiries

More details about each partner are provided in Appendix A.

4. The ACCESS Project: Technical Description

a. *Project specifics*

The ACCESS (Assisting Communities to Connect to Electric Sustainable Sources) project has piloted a way of enabling renewable energy generators to operate at full capacity despite local and/or regional restrictions on how much power can be transmitted to the national grid.

The Mull hydro turbine, 'Garmony hydro' is connected to the electricity network and has a rated output capacity of 400kW. Given the amount of existing renewable projects on the peripheries of the distribution network, and their inherent 'inflexibility' (ie, generally based on the weather!), new generators are now often limited to a connection offer limiting their export to a maximum 50kW. A 50KW restriction of this type currently applies to all new generators connecting along almost the entire Argyll coast (including Mull), among many other areas of Scotland. This type of offer generally means such installations are no longer financially feasible for the community to seek local or commercial investment.

ACCESS has sought to overcome this problem by creating a system whereby the amount of power that is exported onto the wider, distribution and/or transmission electricity networks is limited by switching on matching 'demand' in the form of electric storage heating, hot water cylinders or electric flow-boilers in local homes on the islands of Mull and Iona. For the purposes of the trial, generator production and on-island intelligent demand were controlled such that the net export from these two network users never exceeded 50KW. This models what could be achieved for new generators facing a 50KW 'constraint' on the network that limits the amount of power allowed onto the higher voltage circuits.

The project aims to show that it is technically, financially and socially feasible to switch on this additional heating load in a way that reduces the impact on the transmission network.

The project has a number of inter-linking elements:

- Supply of power from a local, community-owned hydroelectric turbine;
- Recruitment of pilot households, small businesses and other 'loads';
- Upgrades to heating equipment (modern storage heaters, flow boilers and hot water cylinders) in over half of these properties and buildings;
- Installation of communication equipment at the generator and on all of the individual heating loads so that the heaters can be switched on to absorb power when required;
- Testing and installation of 'smart' controllers that respond to signals;
- Creation of a manual rebate payment for local participants and for the local community generator and
- Demonstration that it is possible to undertake these innovative measures within the existing strict regulations governing the operation of the distribution network such that the concept can be more broadly applied in network-constrained areas as a business-as-usual solution.

b. *The Local Electricity Network*

Mull’s electricity network is made up of a 33kV distribution grid with 11kV feeders for the more sparsely populated areas. These values refer to the voltage of the electricity being carried by the cables. Mull is fed primarily via the 33kV undersea connection from the mainland (Tulloch switching station by Oban), which lands at the Lochdonhead substation at the eastern end of the island. There is a backup connection, again via a 33kV undersea cable, from Lochaline but this is not usually connected.

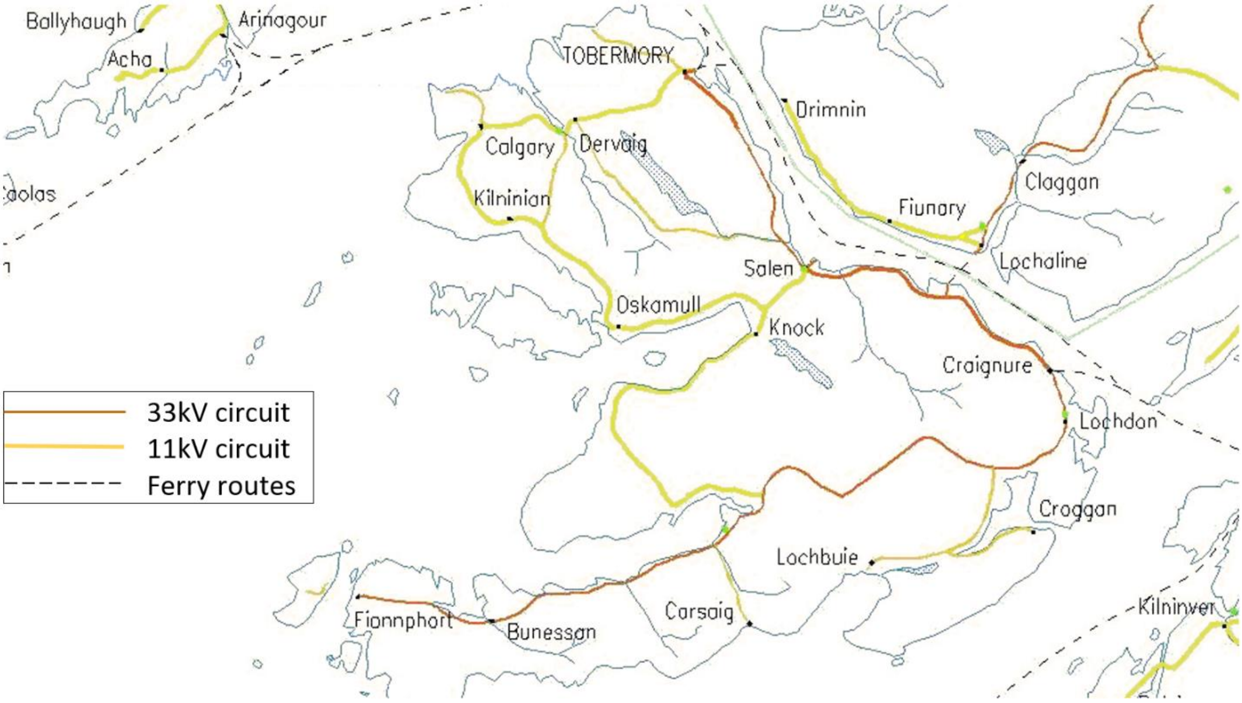
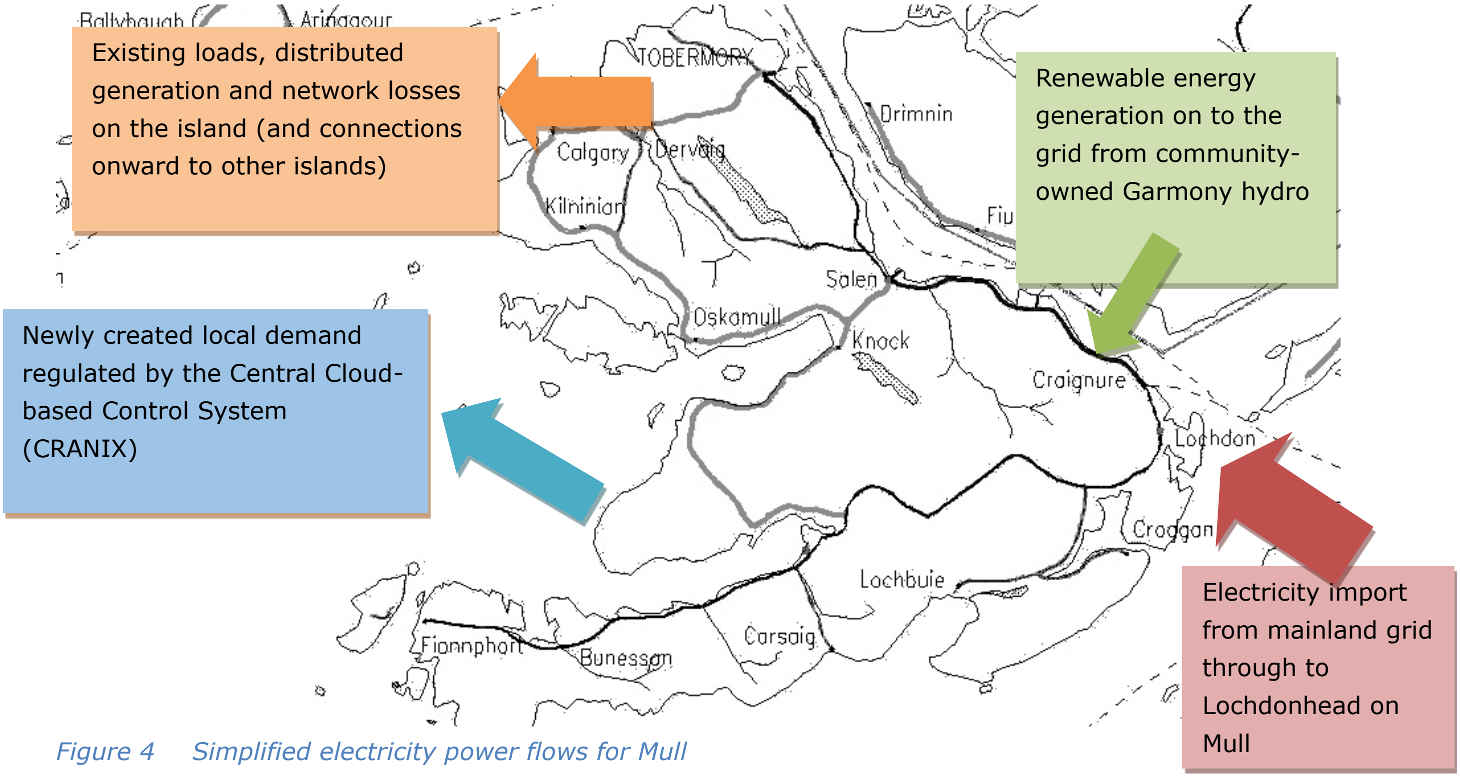


Figure 3 Map of Mull showing HV circuits



Existing loads, distributed generation and network losses on the island (and connections onward to other islands)

Renewable energy generation on to the grid from community-owned Garmony hydro

Newly created local demand regulated by the Central Cloud-based Control System (CRANIX)

Electricity import from mainland grid through to Lochdonhead on Mull

Figure 4 Simplified electricity power flows for Mull

Cranix is the name given to the controlled load used at any moment by the project. Figure 4 shows the electrical power flows that must be balanced by the system. Assuming that we have captured all electricity flows within the four aspects shown in the texts boxes of Figure 4, we can express the power balance for the island as follows:

Import + Garmony Generation = Cranix Load + Other Loads

At every moment, the local generation plus the imported electricity will equal the Cranix loads plus all other network loads and losses (including interconnectors to other islands, etc)[1]. Power in must equal power out. The power in is the imported power and the generation from Garmony; the power out is absorbed by the various loads ('Other Loads') and the controllable heaters that have been switched on (the 'Cranix' load)

'Cranix' is made up of storage heaters, hot water cylinders and flow boilers that are participating in the project and have capacity to absorb power at that point.

'Other Loads' includes all other electrical activity (connected to the mains) taking place on the island. This is homes, shops, farms, other businesses, distributed generation like domestic solar panels and also accounts for the inevitable losses in the wires and transformers of the electricity network.

The first three components of the above equation are measured in this project and the middle two (generation and Cranix loads) can be controlled by the ACCESS solution (within certain limitations).

Mull has always imported power from the mainland and its usual demand or 'load', the amount of electrical energy it requires from the network, is a necessary part of the total load that is counted on by the Distribution Network Operator (in this case Scottish and Southern Energy Networks) to match or 'absorb' some of the generation from nearby large wind farms. The interplay between the existing loads and generators on Mull results in a minimum normal import threshold from Mull, which SSEN wishes to maintain. This threshold power value was used for some of the tests in the ACCESS Trial to ensure that net export from teh generator and controlled loads did not exceed 50KW, and replicate the basis upon which a real-life constrained generator would operate.

When the import of electricity on to the island falls below this threshold, either the generator needs to reduce its output or the Cranix loads need to be switched on to absorb some of the Garmony hydro scheme's generation. Either response will bring the island's import value above the minimum threshold again.

c. ***Supply, Network Constraint and Demand Matching***

The network situation on Mull and Iona serves as a useful example of other networks constrained by export limits given its single, and occasionally constrained connection, to the wider grid and abundant on-island renewable resource.

i. Supply: The Garmony Hydro Scheme on Mull

Garmony Hydro is a run of river hydro scheme owned by Green Energy Mull on behalf of the Mull and Iona Community Trust at Garmony, on the eastern side of the Isle of Mull. Its maximum output level of 400kW is determined by the maximum generation possible given the licensed river abstraction rate from the Scottish Environmental Protection Agency (SEPA). The capacity factor, or the actual electrical energy output over a given period of time over the maximum possible electrical energy output over that same timeframe, is around 30%, giving a total annual generation of 1,000 MWh. Note the roughly triangular distribution of power in Figure 5 below.

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[1] Other generators, including PV installations are dealt with here as 'negative loads' in the same way that most industry processes reckon them.

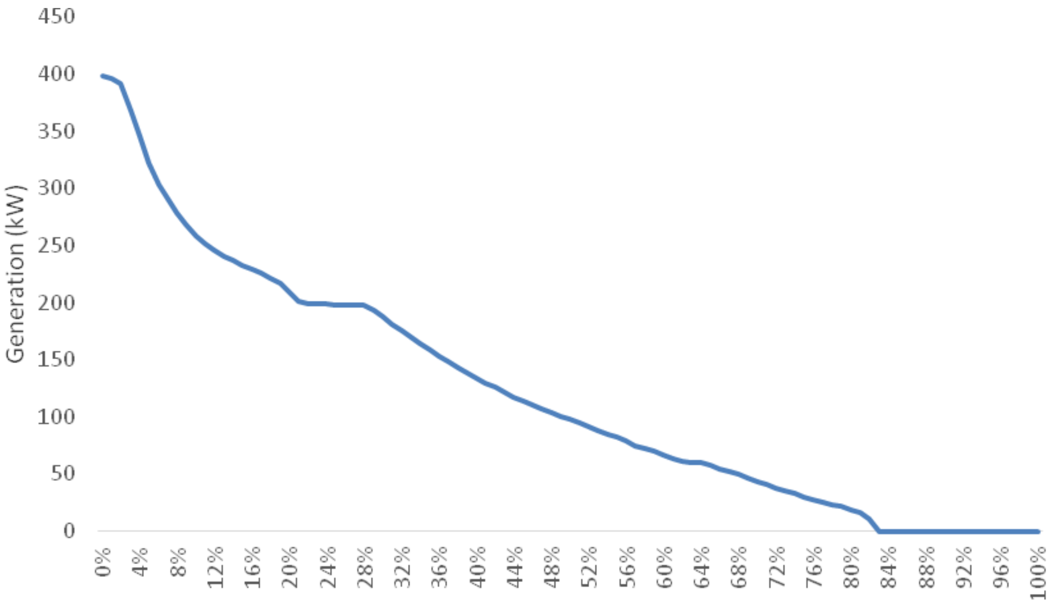

Figure 5 Garmony flow duration curve

The river is not dammed, so water cannot be stored and released at times of high electrical demand; this produces a flat annual daily generation profile as shown in Figure 6.

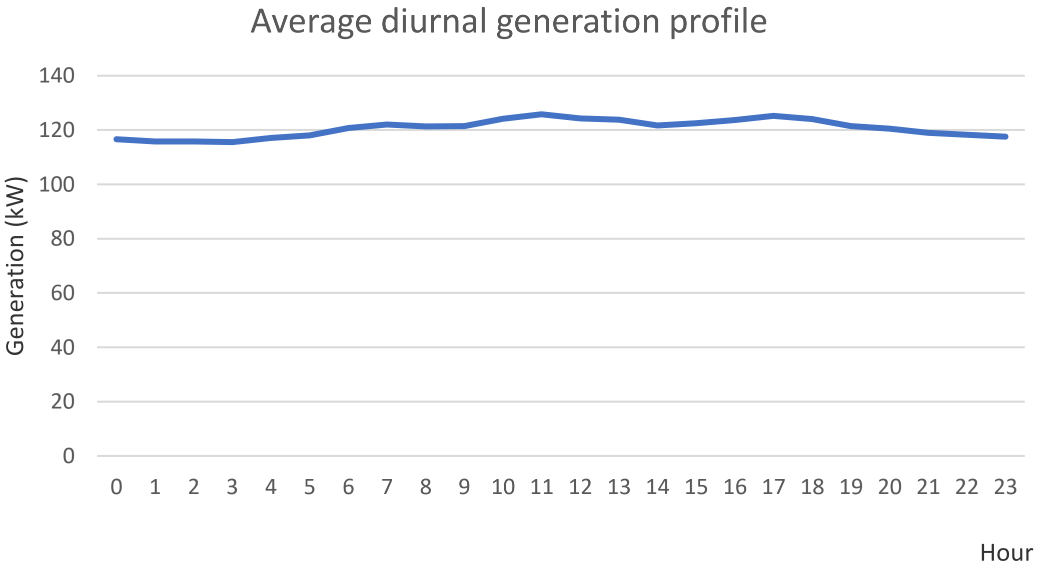

Figure 6 Average Garmony generation across the day.

Figure 7 shows monthly rainfall levels vary throughout the year, producing a pronounced seasonal trend in generation, with more electricity produced in winter than summer and minimum electricity generation levels in spring. Note that, in the graph below, monthly generation is based on data from 2015 to 2017 and rainfall data is from 1981 to 2010[2].

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[2] UK Met Office Long Term Rainfall Data.

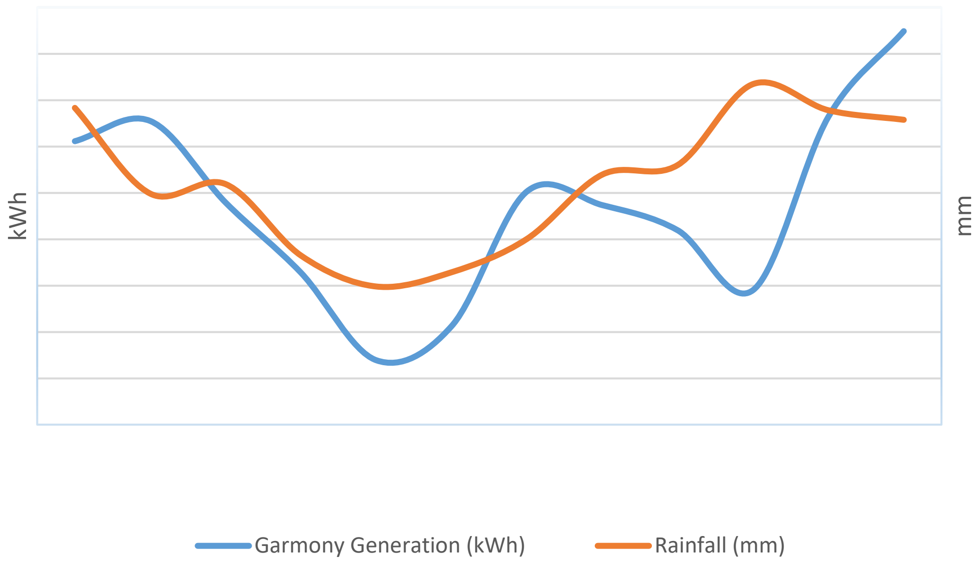

Figure 7 Garmony monthly generation and Long Term Rainfall.

The 1000 MWh of power generated by Garmony Hydro each year attracts a Feed-in-Tariff (FiT) of £150/MWh (15p/kWh). All exported generation from Garmony is sold through a long-term power purchase agreement (PPA) [3] at £55/MWh (5.5p/kWh) to renewable-only supplier, Solarplicity. This means that each MWh exported to the grid earns £205 (for comparison, the 2016 average UK wholesale spot price for power was £38/MWh[4]).

Garmony is connected to the 33kV island network via a pole-mounted breaker (see Figure 8).

---

[3] Power purchase agreements are struck between generators and suppliers to de-risk generation project financing. In this case, the PPA price is above the 2016 wholesale power price, it may be that this cost is offset by reputational benefits for the supplier, and reduction in exposure to price fluctuation risks, due to the longer duration of PPA contracts.

[4] Elexon Data Portal MWh or megawatt-hours are a thousand kilowatt-hours, the units used in electricity bills.

Figure 8 Garmony hydro's pole-mounted transformer

ii. Network Constraint on Mull and Iona

There are no grid-connected, fixed fossil fuel generators on Mull, which has historically imported all electricity used on the island. As discussed in section 4a above, when new renewable generation, like the Garmony Hydro Scheme, connects to the island electricity network it decreases the total imported power as local demand is met by local renewable generation. It is therefore possible that Mull's import requirement for electricity from the mainland will fall significantly. This could cause voltages to rise on the mainland electricity network; a situation the network may be unable to accommodate.

During the construction of Garmony Hydro, it was originally understood that the generator would not be able to export all of its output onto the electricity network. Following a more detailed analysis it was discovered that there was not a need to reduce ('constrain') the output for the sake of the network. Although the connection is therefore 'unconstrained', a control system to curtail Garmony generation based on a *simulated* constraint was installed as part of this project and the ability to match generation to set-points investigated in field trials.

iii. Demand Matching: Local Storage Heaters and Hot Water Cylinders

Where a network's immediate or long-term capacity to absorb renewable generation is limited by the export rating of a connection to the wider grid, turn-up of local electrical appliances can reduce the export levels and so mitigate any constraint. Domestic heating using storage heaters or hot water cylinders is an ideal candidate 'demand' for local energy matching; UK homes use over three times as much energy for heating and hot water as appliances and, unlike instantaneous appliance demand, heat can be stored for later use either in storage heaters or in hot water cylinders.

Storage heaters use a resistive element to warm a large concrete mass up to temperatures of around 700°C. Typically heaters are charged overnight (see Figure 9), circulating heat into the air over the course of the day. Modern heaters can store heat for many hours, controlling air flow to retain heat or circulate it into the room. Hot water cylinders similarly store heat but as hot water in an insulated tank that can be used when needed. Homes with ‘two-tier’ or ‘off-peak’ tariffs will typically heat the bulk of their water overnight in the same way as storage heaters.

Storage heaters are primarily found in homes not connected to the gas grid; the domestic cost of gas is around 3p/kWh, while domestic electricity costs no less that 8p/kWh, even on the low rate of two-rate tariffs associated with overnight charging. The higher cost of unit heat means electrically heated homes are much more likely to be in fuel poverty:

> *In Scotland … 48% of households with storage heating systems and 68% of households with direct-acting electric heating are in fuel poverty, compared to 31% of households that use mains gas[5].*

By managing the charging of storage heaters, hot water cylinders and flow boilers to match local generation (that might otherwise need to be curtailed by the DNO to prevent network imbalance) electricity can be procured more cheaply, reducing the energy bills for these homes, and obtained from renewable sources.

Figure 9 Shows the Average Baseline Storage Heater Charging Profile across ACCESS Participants. Most heating occurs overnight with some additional charging in the early afternoon for heaters in properties with permitting energy tariffs.

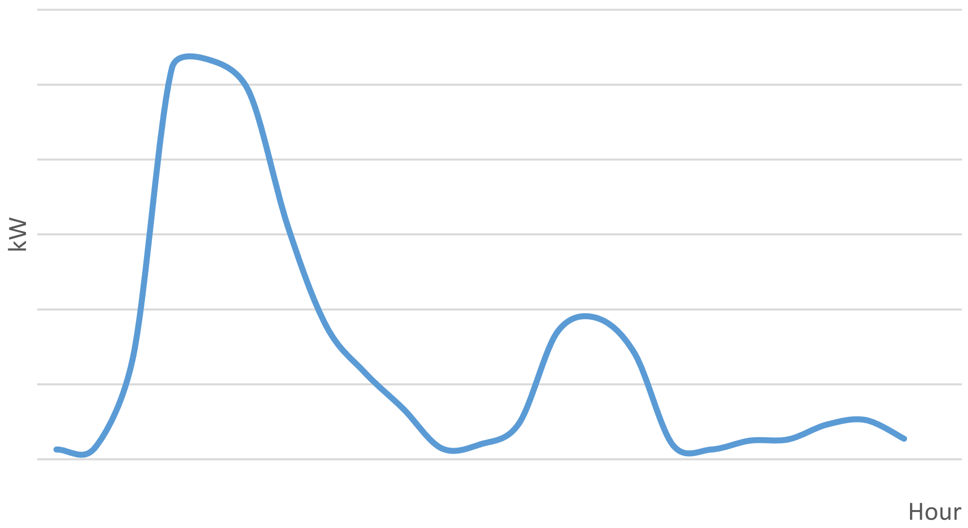

Figure 9 Average Baseline Storage Heater Charging Profile

iv. Demand Matching

As storage heaters release heat to warm homes many hours after charging, they constitute:

> *an established source of shiftable load in the UK and tapping into a proportion of this load could secure significant flexibility[6]*

In this section we consider how this flexibly might be leveraged to absorb “excess” renewable supply, while:

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[6] Ofgem Insights paper on households with electric and other non-gas heating (2015)

1. Keeping the dwelling within the required temperature range and providing required hot water
2. Considering the cost of moving charging outside of low tariff periods where more favourable tariffs do not yet exist.

The graph below (Figure 10) shows the opportunity for better matching the heat demand with the generation from Garmony Hydro.

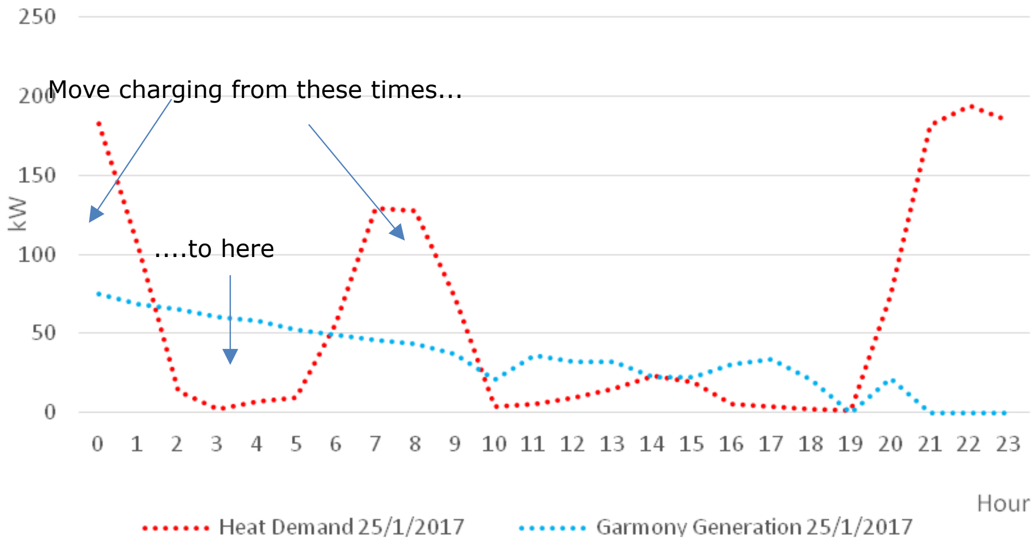

Figure 10 Domestic heating demand and Garmony generation profiles over an average day

As depicted in Figure 10, heater charging can be managed to match the local domestic electrical heating demand to Garmony's generation supply, allowing domestic heaters to absorb more renewable generation from Garmoy than they would under their usual operation. This ultimately mitigates curtailment. There are few technical barriers to demand management of an "aggregator ready" storage heater[7]; each heater can be moved to a set-point in response to a remote, control signal very quickly without long-term degradation of the heater.

v. *Tariff implications*

There are, however, currently economic costs associated with changing storage heater charging times under existing energy tariffs: most homes using storage heaters are billed for their electricity under a two-rate tariff, comprising a 'low' and a 'normal-rate' period (such as Economy 7 or Economy 10). These tariffs limit users to charge their heaters overnight (and on some tariffs, at other periods of low system demand, eg, Total Heating Total Control (THTC) tariffs). Table 1 overleaf summarises these tariffs based on SSE's 2018 figures. As shown in the table, electricity prices are higher for more flexible tariffs (especially those that permit afternoon heater charging). Typically, low and normal rate consumption are recorded on distinct physical meters.

As such, storage heater charge management can mitigate curtailment of local generation during off-peak hours at no cost but matching peak hour generation increases user heating costs by between 3 and 10p/kWh. To compensate for this for the purposes of this project, ahead of a commercial 'local energy tariff' being readily available, a manual rebate mechanism was put in place to compensate participants (please see section 4d below for more details).

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[7] Heaters used in this study did not contain embedded control telemetry but were augmented to record charging data and respond to control signals.

As well as financial or energy 'supply' barriers, there are also practical limits on the extent to which flexible heater charging can mitigate curtailment: the average UK home consumes 10MWh[8] of heat annually, though annual demand for electric heating across the ACCESS scheme is 6MWh[9]—despite the colder than average UK climate—as other fuels, such as oil or wood, augment heating demand on the islands. Therefore, the roughly 1,000 MWh/year generated by Garmony is three times the annual requirement for electric heating across the 61[10] homes participating in the ACCESS Trial.

Table 1 Examples of SSE Two-rate Tariffs[11].

	Off Peak Hours	Peak Rate (p/kWh)	Off-Peak Rate (p/kWh)
Domestic Economy	8 hours from around midnight	19.68	12.13
THTC	Three daily periods. Meter is controlled by radio teleswitch, with longer off-peak periods in colder weather	21.02	12.20
Standard Economy 10	10 Hours off peak split across 3 periods overnight and during the day	19.48	14.96

Seasonal heating demand across these homes is shown below in Figure 11 alongside Garmony's electricity generation output.

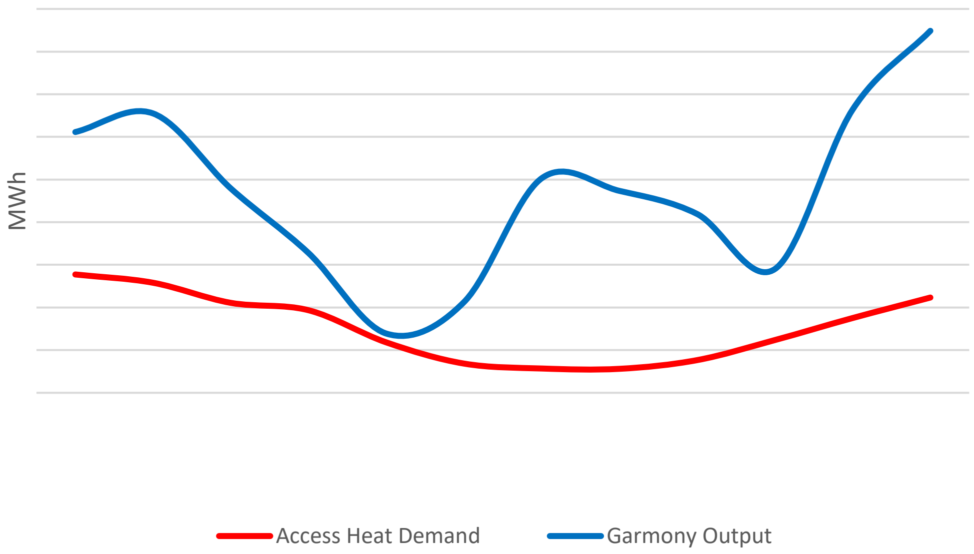

Figure 11 Monthly Garmony generation and ACCESS Participant Heat Demand

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[8] Energy consumption in the UK

[9] See appendix B.

[10] For which data was collected. Using data from the Scottish Housing Condition Survey (SHCS), we estimate the average space heating demand across the 12% of homes that are electrically heated is around 12MWh per year, twice the figure for ACCESS participants, see section 6.b.

[11] SSE prices for PA75 Postcode District excluding VAT for credit customers. From: https://sse.co.uk/cs/Satellite Accessed 6 September 2018.

The volume of 'over-supply' by Garmony, in comparison to local demand, that can be absorbed is also limited both by the rating of the heaters (power) and—more significantly—the seasonal heating demand (energy) of the heaters. This is further explained in the section below.

vi. Energy

The project charging data implies household heating demand figures for ACCESS participants of over 30kWh (nearly four hours' heater charging) average per day in January and 13kWh (1.5 hours' charging) per day in May. The capacity of storage heaters is around seven hours' charge, so a typical household's heaters hold around 55kWh at maximum charge. Please see Table 2 below. Modern storage heaters lose heat at a minimum rate of 2% per hour[12]; we use this figure in our charge-optimization model. On this basis, a heater can retain just over half of the heat stored over a 24-hour period. Therefore, heaters might charge fully using "surplus" power while still being able to meet the typical daily January demand of a house nearly a day later.[13]

vii. Power

Individual heaters used in the project were rated between 1kW and 4 kW and participating houses typically had three or four heaters, averaging a total of around 8kW[14]. This figure is less than the power of a 'wet' central heating boiler that might be installed in a similar home connected to the gas network and underlines the requirement to charge storage heaters before heating is needed so that the power 'rush' is not too great.

Table 2 Specification of Quantum Storage Heaters: Each can store 7 Hours' Charge[15]

Model	Element Rating @ 230V (W)	Storage Capacity (kWh)	Hour's Storage Capacity
QM050	1,020	7.2	7.06
QM070	1,560	10.9	6.99
QM100	2,220	15.5	6.98
QM125	2,760	19.3	6.99
QM150	3,300	23.1	7.00

Because of these energy and power ratings, curtailment matching is limited by:

- Operational implications of meeting thermal demand.
- The respective daily and seasonal distribution of curtailment and thermal demand and
- The need to ensure the value of the avoided curtailment is greater than the increase in consumer bills.

The effect of the second and third points on curtailment mitigation capacity is illustrated in Figure 12 below. Here cost considerations limit the ability of flexible heater charging to match generation but, even at no regard to cost increase, seasonal mismatch limits the curtailment mitigation. Figure 12shows:

- Electric heater charging unmatched to oversupply mitigates very little curtailment (Passive System)

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[12] Conversation with project partner Glen Dimplex, who supply most of UK storage heater market.

[13] In fact, the effect of managed charging is a smoother charging profile, so unwanted heat loss is typically reduced overall by managed charging.

[14] Some houses in the scheme have as many as 6 heaters and, those who augment their heating with significant amounts of heating oil, as few as one.

[15] Quantum Series G Instructions, Quantum Brochure

- Matching charging to oversupply during off-peak periods does better but only absorbs less than half of the curtailment (since off-peak hours comprise less than half the time-assuming all other loads are equal).
- Ignoring tariff structures, curtailment avoidance is constrained by seasonal distribution; some summer oversupply cannot be mitigated as there is too little thermal demand.

This analysis suggests that not all curtailment can be fully absorbed by storage heaters due to the seasonal mismatch between generation and heat demand. Flexible tariffs that allow bringing on of loads at times of over-supply without the financial penalties of a fixed time-of-use tariff can significantly increase the amount of curtailment reduction.

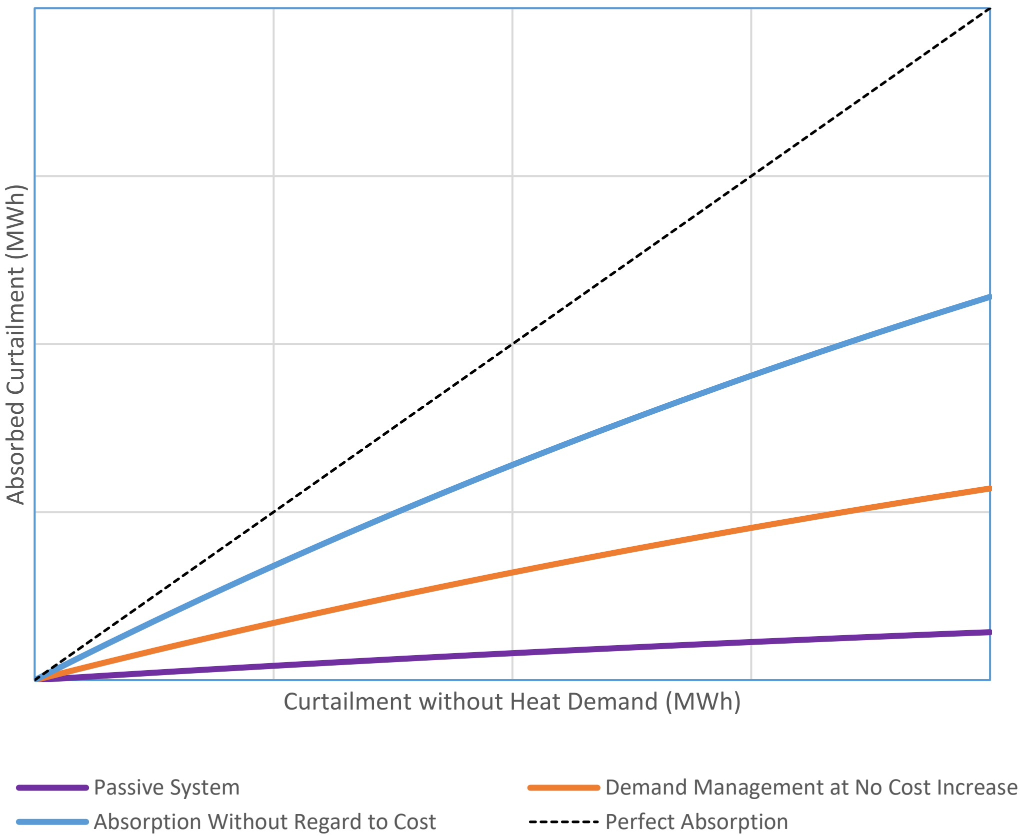

Figure 12 Graph of absorbed curtailment for various protocols

5. Results of the ACCESS Trials

Project Partner, VCharge, conducted various tests to ensure that the ACCESS communication and control system functioned as expected, that communications were reliable and the system was fail-safe in their operation. Full, technical reports are shown in annexe 0 on page 94.

a. *Live-following tests: 14 November 2017*

The first test was to ensure that the normal operating mode of the SOTN and VSCon worked. The State of the Network (SOTN) controller supervises the overall condition of the various components and reports any anomalies. The VSCon is VCharge’s interface module that establishes a communications and control link between the generator and VCharge's cloud-based control system.. To begin with a simulated local load was used rather than domestic heating assets, to reduce the impact of any testing error on householders. Power was varied from 50 to 160kW.

A second test was then completed to verify that the virtual constraint of 50kW, which was applied to Garmony as part of these Trials, would not be violated in the event of communication to the VCharge VSCon failing. This test was also designed to show that normal operation of the ACCESS Communication system would resume upon the communications being re-established. To simulate a communication failure, the satellite modem was unplugged.

This test was to ensure that if the VSCon were to fail, the generator controller would take back control of the hydro plant. Before the VSCon control was to be disabled, the VCharge system was configured with a fixed hydro set point to make observing the change easier.

b. *Live-following tests: 20 November 2017*

This test, which had to await significant rainfall so that the generator was outputting maximally, was designed to examine the normal operating mode of the VCharge control systems. Real, live Mull Cranix data was used-. The Cranix was in control of the heaters but the control system was set up so that it would send a signal back to the Cranix as the grid demand signal. This tested the communication system without activating any curtailment.

To ensure that the virtual 50kW constraint on Garmony would not be violated when the communication failed to the VSCon, another test was conducted. This test was a repeat of the previous test to ensure the delay in re-establishing communications was fixed. It also ensured that normal operation resumes upon the communication links being re-established. As before, to instigate a comms failure, the satellite modem was unplugged.

A third test verified that recovery from VSCon control works as expected.

c. *Live-following tests: 22 December 2017*

This test was designed to simulate system response to a breach of the overall minimum import level, as recorded by monitoring of power flows entering Mull at Lochdonhead substation.

In the simulated scenario, a breach of the minimum import is recorded, requiring progressive reduction of net export from Garmony over 5 minutes. The constraint remains in place for 5min,then is rapidly lifted, allowing Garmony net export to revert to 400kW. The system receives an initial curtailment request of 100kW which increases 1kW every second until it reaches 400kW. While the signal is changing, the system should turn on domestic heating loads to as required.

d. *Continuous live-following tests: 12–23 February 2018*

A Continuous Live-Following test was carried out over a 2-week period in February 2018. Prior to this, the previous testing achieved satisfactory generation curtailment at Garmony and proved that the system operated in a safe manner in the event of loss of communications. As a result, these aspects of the system were not re-tested during this 2-week test.

The storage heaters within the Cranix load were to absorb the generated power during both on-and off-peak times but using off-peak periods wherever possible. If there were more heaters needing charging than could be supplied by the generator, some heaters would defer charging until later. (The system schedules heater charging in an equitable fashion.) If no, or insufficient, power was generated, the storage heaters would revert to the standard off-peak charging regime. No generation was to be curtailed during this test.

-A second test verified that the Cranix Load followed available generation during off-peak and on-peak periods dependent on turbine production periods. When possible, heaters should charge during off-peak periods. However, in the situation where Garmony's electricity generation is only available during a peak energy tariff period, heaters should delay charging (where applicable) until turbine production begins.

A third test was carried out to ensure that the Cranix Load matched the generation from Garmony when the desired Cranix Load exceeds generation. In this test scenario, the participant's heaters, hot water cylinders or flow boilers would absorb all of the available power even if the cumulative load is more than the generated power. As a result, the charging period may be extended to ensure that all heaters were charged sufficiently. Please see Figure 13 below, which shows how the Cranix load closely tracks the hydro generation. In the event that the turbine wss not producing sufficient power, heaters were to charge regularly, ie, no load curtailment.

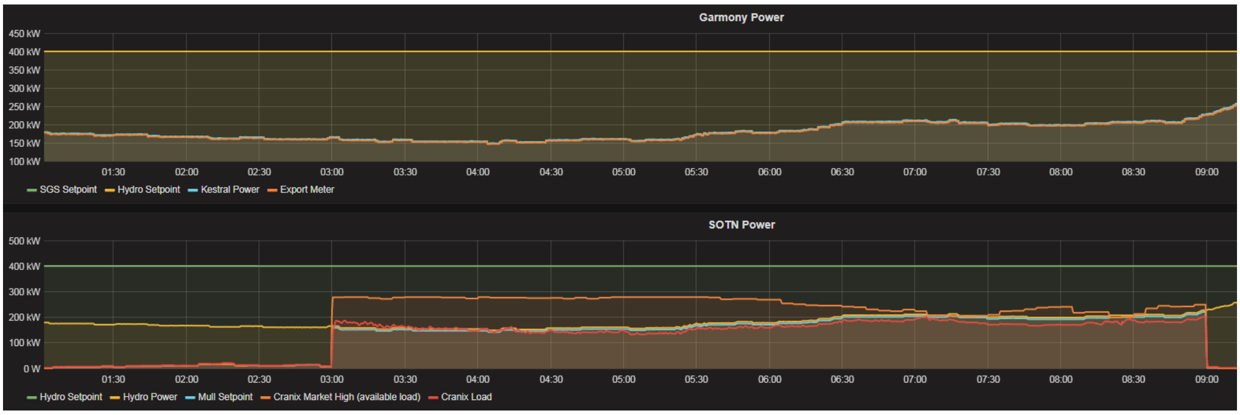

Figure 13 Cranix load following generation

The Continuous live-following tests were considered a success and the VCharge System displayed behaviours in line with required objectives.

e. *Live Curtailment Signal Response testing: 9–18 March 2018*

Following the successful live-following tests in February, a test was then required to show how the controllable domestic loads could be used to respond to a live curtailment signal (SGS signal) from Lochdonhead substation. This signal gives a generator set-point based on the electricity import onto the island as measured at Lochdonhead. When the import reduces to close to the minimum import that should be maintained (according to the artificial conditions that we are simulating for this exercise), the live curtailment signal will reduce below the standard 400kW to indicate that the generator should reduce its output. The measurement devices on the electricity network cables at the substation send signals via the VSCon to the control system. Because the previous testing used a simulated SGS signal (as carried out on 22 December), this final test was therefore required to show the live network signal triggering a curtailment event and assess the response of the ACCESS communication system.

This final test was designed to meet the following key objectives: when the SGS setpoint signal (that provides a maximum target output for the generator) drops below 400 kW (ie, a curtailment event should be triggered), as a result of under-import nearing the Lochdonhead substation network threshold, the controllable domestic load should turn on so that this threshold is not breached. That is to say, the domestic heating assets should remain on until either the SGS setpoint returns to 400 kW or the heaters cannot absorb any more energy whereupon the heaters will stop charging. No generation curtailment was to take place as a result of the interventions, however in a truly constrained network scenario, this would signal for Garmony's generation to be ramped down. This test therefore demonstrated how aggregated load can be used to control the amount of energy being imported and, if required, exported from the island.

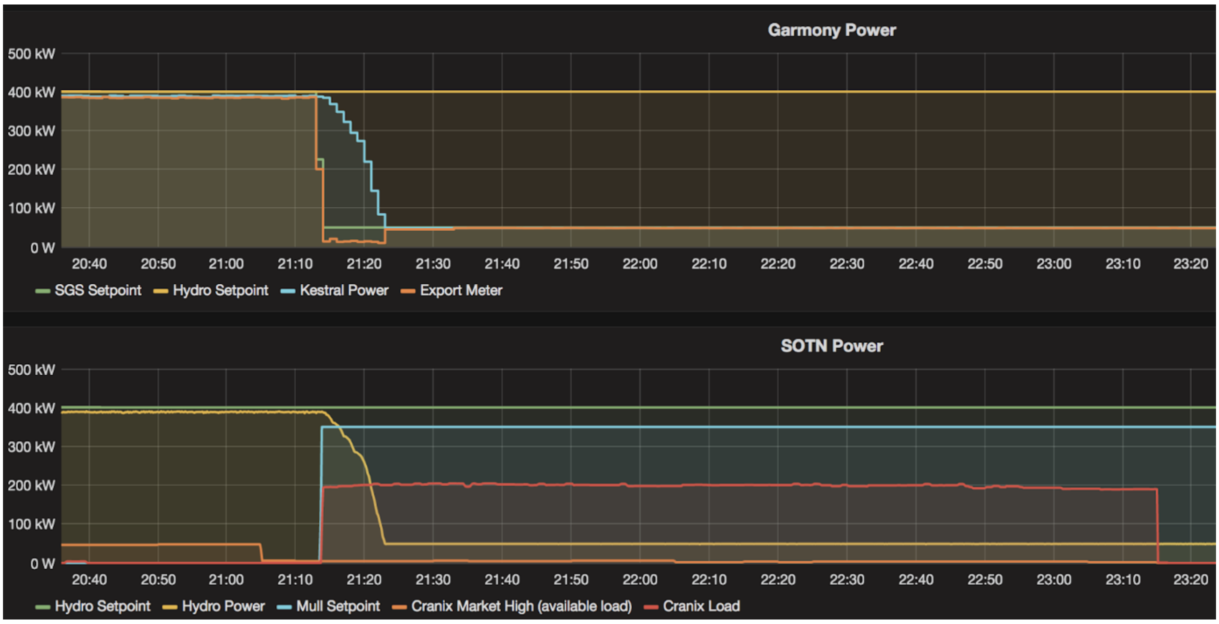

Figure 14 Prolonged response to SGS signal

Figure 14 shows a screenshot from ACCESS communication control software showing a prolonged response to SGS signal (two hours from 21:13 to 23:14). The Cranix Load (red line) increases in response to the call for load (blue line—'Mull Setpoint').

In summary, the ACCESS Trial tests were completed successfully and the ACCESS Communication System displayed behaviours in line with the Project's required objectives.

6. Analysis of the ACCESS Trial Results and Modelling

a. ***Potential for curtailment reduction through active demand management***

In this section of the report, the results of the Project Modelling are shown. Modelling was undertaken to quantify the benefits and costs outlined in the previous chapters. This analysis is based is on the following project data:

- Storage heater power and capacities are taken from model data supplied by manufacturers, Glen Dimplex and from records of heater installations for the project.
- Historical heater charging profiles and brick temperature records, supplied by VCharge, were used to determine heat demand and heater charging profiles (the methodology is explained in appendix B)
- Participant tariff rates and peak/off peak hours, supplied by SSE Retail.
- 10-minute interval Lochdonhead substation power flow data supplied from SSEN Future Networks
- 15-minute interval Garmony generation and river height data collected by Mull and Iona Community Trust.

i. Model Operation

The model determines a charging profile for each heater in the participant's house for a typical year[16]. For each hour, it considers:

- the heater's state of charge
- the user thermal demand (ie, how much heat the householder wants from it).
- total Garmony Hydro Scheme generation
- the net flow of power due to other electricity generators and electrical demands on the island.

It then charges the heater, so as to:

- Satisfy user heating demand
- Reduce curtailment (ie, ramping down/ switching off) of Garmony (subject to price and other considerations)
- (Potentially) help manage the system balance between supply and demand. Provision of the various ancillary services (AS) the Electricity System Operator uses to regulate the power system of the electricity network is discussed in section 6.c.

In this section of the report, results from the following three approaches to matching demand and supply are presented:

1. Passive Charging (Baseline)—Heater is operated according to its usual profile, which does not consider local generation. We create this profile from charging data for periods of heater operation free from external control, see appendix B.
2. Opportunistic Charging—Heater follows baseline charging but turns up to mitigate curtailment or down (to avoid electricity import on to the island if it the heater is above its baseline "expected" storage level and there is no available local generation).
3. Forecast Charging—Heater looks ahead and maximises the amount of charge it can absorb over the next 24 hours, without any consideration of a time of use tariff times (or electricity prices).

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[16] See appendix C.

Under each charging scenario, maximum stored heat levels are constrained to the baseline daily maximum and a minimum of 2% of stored heat is vented to the room each hour.

For each approach, both the retail energy tariff and wholesale network power costs of the charging profiles[17] are presented (wholesale power prices are discussed further in section 6.f).

Where useful, the No Thermal Demand curtailment level, for which all heater demand is removed is also shown; this helps illustrate the difference in curtailment mitigated between the baseline and actively managed charging scenarios.

ii. Results from the Base Case

A. Supply and Flexible Demand

Garmony generates 960MWh in an average year[18]. The long-term reference electric heating demand of the 61 houses participating in the ACCESS scheme in Year 3 of the Project is 370MWh—less than 40% of this figure.

B. Other Electrical Demand

There is considerable additional load on the island, associated with the roughly 1,000 households plus commercial and industrial demand. SSEN 10-minute electrical current data for the two three-phase 33kV network branches at Lochdonhead shows the minimum import level (net of Garmony's generation) is 375kW if the demand for heating associated with the ACCESS scheme is subtracted. All of the generation from Garmony can in reality be absorbed locally, however the modelling undertaken explores a number of scenarios in which total island load has been scaled to model different network topologies, as discussed in section 4.C below.

Scaling the total unmanaged electrical demand in the modelled scenario so that there are six months each of net power import and export, gives us the following monthly profile.

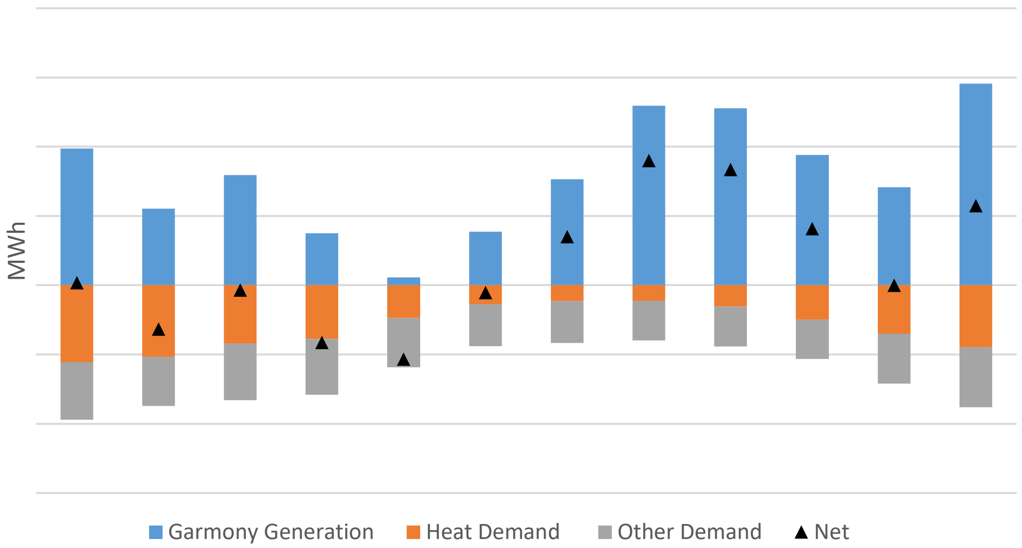

Figure 15 Heat and appliance demands following similar seasonal distributions.

In the modelled scenario, there are six months with net export (July–January, excluding November) and six months with net import (February to June plus November)

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[17] Retail prices are considered by the Opportunistic Charging Algorithm but not the Forecast approach.

[18] See appendix 10.

C. Export Constraint

In this section we present the model results, indicating how much curtailment may be avoided by the ACCESS platform.

Unlike in the ACCESS live trials, where Garmony was curtailed each time the net export from the generator minus the controlled loads exceeded 50KW, the following modelling assumes that constraint is applied only when Garmony generation minus *all loads and generation on the Island* (controlled and non-controlled) results in net export of 50KW or greater. This more closely replicates the constraint parameters used in existing commercial non-firm connections, and allows our modelling to explore the overall effect of such a system on the network.

The exogenous island demand profile - due to loads and generators not participating in the project - is taken SSE half hourly load data from Lochdonhead. As the minimum export on Mull is greater than the 400kW Garmony maximum output, this profile is scaled so that unmatched generation can give rise to net exports of more than 50kW. We scale the exogenous demand to be equal to the total thermal demand, making our modelling representative of situations where the managed and unmanaged loads are of comparable size.

By scaling the net export limit, we create scenarios in which, 5%, 10% and 20% of Garmony output is curtailed; at these rates of curtailment, generator income will be significantly reduced but the overall project finances typically would not become unviable. As such, these levels are typical of the range of Balancing Mechanism (BM) participating wind farm curtailment levels seen across Scotland[19] (see Figure 16).

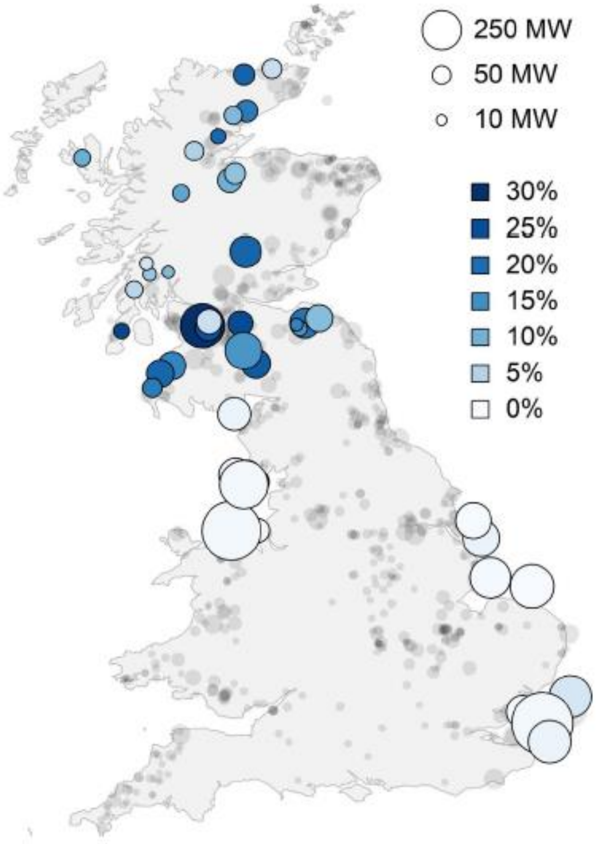

Figure 16 Curtailment across BM-connected wind farms

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[19] Short-term integration costs of variable renewable energy: Wind curtailment and balancing in Britain and Germany

The export connection capacities modelled and the associated baseline curtailment levels are shown in Table 3 below and the relationship between export limits and curtailment is discussed in appendix D.a.

Table 3 ACCESS Modelled Scenarios

Curtailment Scenario	Export Capacity [kW]	Baseline Curtailment [MWh (%)]
Low	285	50 (5%)
Central	240	100 (10%)
High	175	195 (20%)

Table 4 Modelled ACCESS Scenario—Input Data

	Low	Central	High
Total Annual Garmony Gen. (MWh)	960		
Total Heat Demand (ACCESS) (MWh)	368		
Other (Appliance) Demand (MWh)	368		
Total Participating Households	61		
Total Heater Power (kW)	528		
Baseline Curtailment (% Generation)	5%	10%	20%
Modelled Allowable Export (kW)	285	240	175
As Share of Garmony Nameplate	72%	60%	44%

iii. Model results

We consider now the extent to which smart, daily (but not seasonal) redistribution of this demand can further mitigate Garmony curtailment levels of between 50 and 200 MWh annually, corresponding to one eighth and one half of the ACCESS scheme domestic thermal demand respectively.

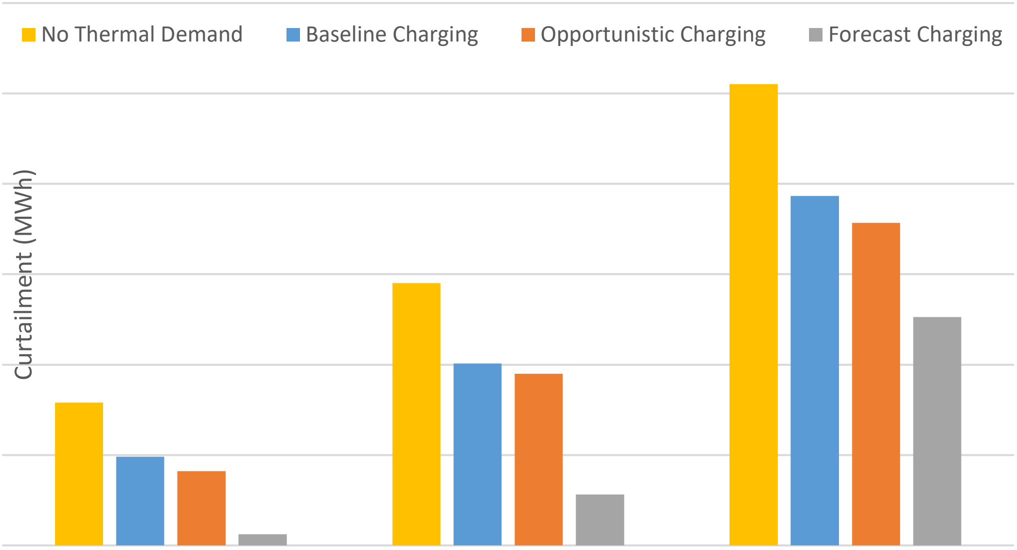

Figure 17 Curtailment levels under various scenarios

The more flexible the charging, the greater the avoided curtailment. The difference between forecast and opportunistic smart charging is at least as large as the difference between no demand and passive demand in all cases. (Figure 17)

Under passive (Baseline) operation, heater charging is distributed compactly, primarily overnight in winter. This heater use pattern mitigates some Garmony curtailment that would be required in the absence of any electric heating. “Passive” curtailment avoidance is given by the difference in curtailment in the No Thermal Demand and the Baseline scenarios. Since:

1. heaters charge at times of low demand by design and
2. demand and generation are positively correlated

the share of curtailment avoided through passive charging (around a third) is greater than the heater’s share of run hours over the course of the year (around 12%).

However, in each case Forecast Charging reduces curtailment from passive levels by more than the improvement from no demand to passive; that is to say, forecast charging avoids twice as much curtailment as baseline operation.

“Opportunistic charging”, also reduces curtailment from heater baseline levels. However, the benefit is considerably less than in the Forecast scenario; constraining charging either through price considerations or by reference to a baseline profile reduces the ability of flexible demand to mitigate renewable curtailment.

Table 5 Curtailment Levels and proportions

	No Thermal Demand	Baseline	Opportunistic Charging	Forecast Charging
Total Curtailment (MWh)	136.2	94.4	80.2	40.0
Share of Generation Curtailed	14.2%	9.8%	8.4%	4.2%
Curtailment Reduction (MWh)		41.8	56.0	96.2
Share of Curtailment Reduced		4%	6%	10%

Curtailment Levels in the Central scenario are reduced far more by forecast than by opportunistic charge management. (Table 5)

Figure 18 below illustrates how the increased foresight and flexibility of forecast charging leads to a flatter, wider charge profile, which prevents more curtailment at Garmony. Forecast charging is nevertheless constrained by the participant’s thermal or heating demands which peak in the morning and evening. In particular, this time of use constraint means Forecast charging does not precisely follow net island generation.

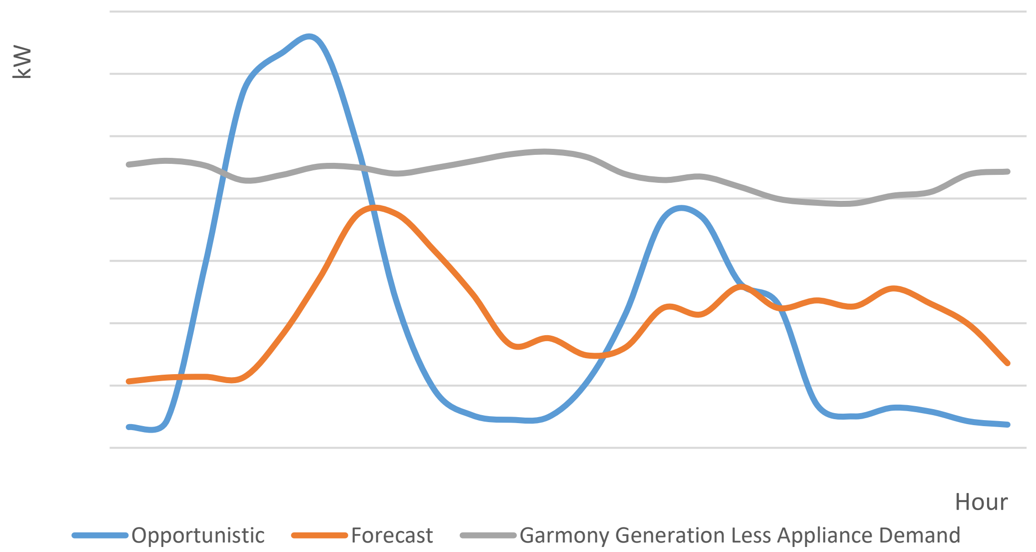

Figure 18 Annual Average Diurnal Actively Managed Charging Profiles.

Forecast charging leads to a broader, shallower profile but is still constrained by thermal demand profile

Even with 24 hours of perfect foresight the curtailment mitigation ability of a storage heater remains a function of the household heat demand profiles.

Considering the monthly curtailment levels in parallel with monthly demand and generation levels (shown in Figure 19) we see that, broadly, Forecast charging avoids all curtailment in months where island demand exceeds generation but not in others (though there is significant curtailment in June). The limit imposed on charging flexibility by thermal comfort requirements do not operationally affect the daily matching of charging and renewable oversupply.

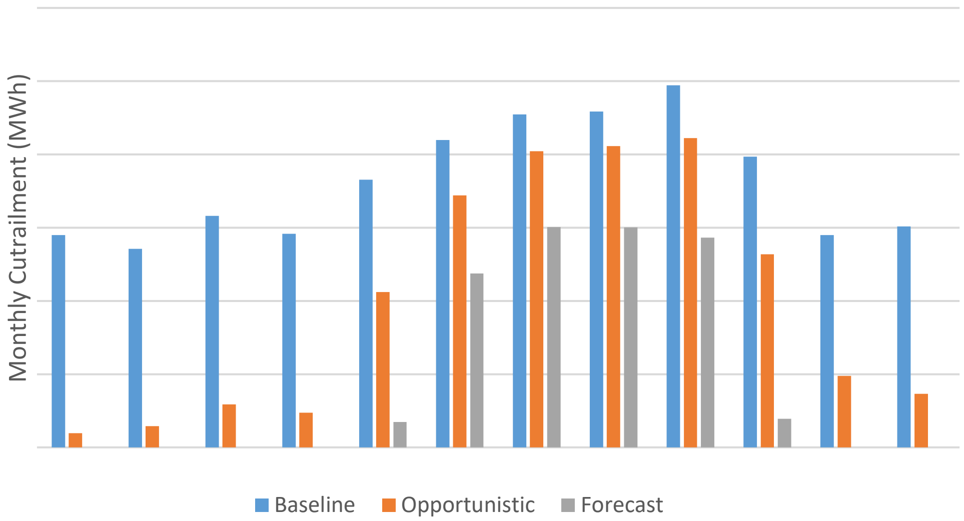

Figure 19 Monthly curtailment by heater-charging approach

Figure 19 suggests that forecast charging dramatically outperforms passive when generation and demand are matched but only improves slightly when generation exceeds demand.

Further, the average heat stored by heaters is not large in those months where Forecast charging obviates curtailment (see Figure 20, below below). Therefore, where:

1. the system has foresight of generation and demand and
2. there is sufficient daily thermal demand to match generation,

modest storage capacities (less than 2kWh per property) can obviate all curtailment - heater capacity is not a limiting factor.

However, where Garmony’s generation is consistently higher than the domestic heating demand, large storage capacities are needed avoid curtailment; the spike in stored heat during August to October indicates that Forecast charging leads to high stored heat levels during times of net oversupply. In these cases, storage capacity will represent the limiting factor for curtailment avoidance.

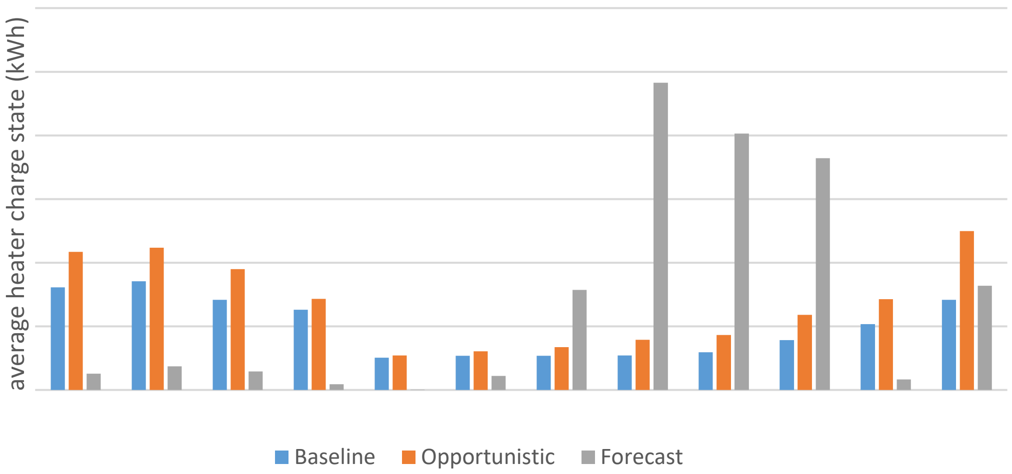

Figure 20 Monthly average household stored heat by demand-matching scenario.

A. Financial Case for Load Matching

As mentioned previously, Garmony generation is worth 20.5p/kWh (£205/MWh), comprising a Power Purchase Agreement (PPA) price of 5.5kWh and a FiT subsidy payment of 15p/kWh.

57 of the 61 homes participating in the ACCESS trial are billed on two-rate tariffs, 46 homes use the SSE Total Heating Total Control (THTC), under which off-peak hours increase in colder weather. The difference in cost between the lower and standard rate across all tariffs is 7.5p/kWh. As a result, opportunistic charging may increase consumer bills by at most £75/MWh of mitigated curtailment (the *forecast* approach does not consider retail tariffs).

The financial analysis for the three curtailment scenarios is shown below, comprising the difference in the increase in consumer bills and:

1. The subsidised FiT power value
2. the PPA value

of the avoided curtailment. The value[20] of the avoided curtailment, which reflects the value of the avoided curtailment without reference to particular energy tariffs, contracts or subsidies is also shown. Table 6 show that customer price increases destroy scheme value unless the generator is generously subsidised.

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[20] The System Value is estimated as the Wholesale Value of the Enabled Generation, minus the increase in the half hourly customer Settlement Cost [under actively managed, compared to passive (baseline), charging]. This is an attempt to ignore the vagaries of supplier pricing structures and renewable energy subsidies, and model the overall value to the system of reducing curtailment by shifting more demand to peak periods.

Table 6 Household avoided curtailment and associated values and costs

		Opportunistic			Forecast		
#		Low	Central	High	Low	Central	High
	Avoided Curtailment (MWh)	0.18	0.23	0.27	0.76	1.07	1.44
1	Total generation value (PPA + FiT) (£)	£37.60	£46.20	£55.10	£156.00	£220.00	£296.00
2	Generation value excluding FiT (£)	£10.10	£12.40	£14.80	£42.00	£59.00	£79.00
3	Retail Bill Increase (£)	£9.80	£12.10	£14.90	£138.00	£141.00	£150.00
4	As share of Baseline Bill	1.3%	1.7%	2.0%	19%	19%	20%
5	Increase per Absorbed MWh	£54.44	£52.61	£55.19	£181.58	£131.78	£104.17
6	Net Generation Value (£) (FiT + PPA -Bill Increase)	£27.90	£34.10	£40.20	£17.70	£78.50	£145.10
7	Net Generation Value excluding FiT (£)	£0.30	£0.30	-£0.10	-£96.00	-£82.00	-£71.00
8	Estimated System Value (£)[20]	£5.70	£6.90	£8.10	£7.50	£22.50	£37.90

Of note:

- Values in row 7 are all marginal or negative, while values in row 6 are all positive and increase with constraint (low to high); curtailed generators find it viable to pay domestic consumers to match their demand only if their generation is rewarded at substantially above market rates, e.g., due—as in this case—to a significant environmental subsidy (FiT).
- The average ACCESS participant heating bill—£750/year—increases by around £50 for each MWh of curtailment avoided under the *Opportunistic* approach, or by over £100 for each MWh using the *Forecast* approach. Customer retail tariffs increase consumer bills even as they provide a service to the energy system! This is why the rebate system was put in place for this project and why subsidies are required to encourage renewable electricity generation.
- The net wholesale value of de-constrained generation is less than the average spot price[21] (£38/MWh) value of the avoided curtailment. The platform allows the generator to sell additional power primarily when demand—and therefore prices—are low. The increase in sales revenue is therefore offset by some increase in user energy procurement costs. We find therefore that de-constraining generators allows them to export additional generation disproportionately at times of low local—and hence typically system—demand.
- As there is no real constraint at Lochdonhead, uncontrolled loads have been scaled to create the desired degree of generator curtailment. This means that model heating demand dominates total island electrical demand and therefore most baseline curtailment occurs in peak-price periods, when heaters are not operating. This results in almost all managed charging for curtailment mitigation moving demand from off-peak to peak periods; leading to unusually high retail bill increases. It is nevertheless the case that static ToU tariffs may not reflect the local balance of supply and demand.

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[21] See Appendix for explanation of spot price and other electricity market structures.

iv. *Other Benefits (Reduced Import, Increased Export) of Flexible Charging*

Under fully flexible charging, not constrained by a fixed profile, local demand can be managed to match net generation to export capacity and in so doing both decrease power imports and exports.

This is shown in the figure below, the large orange block at 7 and 8 am in the left-hand chart shows heaters absorbing power that could be exported. Under active charging, most of this load is distributed to earlier and later in the day (as all charging is subject to meeting consumer thermal comfort levels there is still some import between 7 and 9 am), increasing the total exported power.

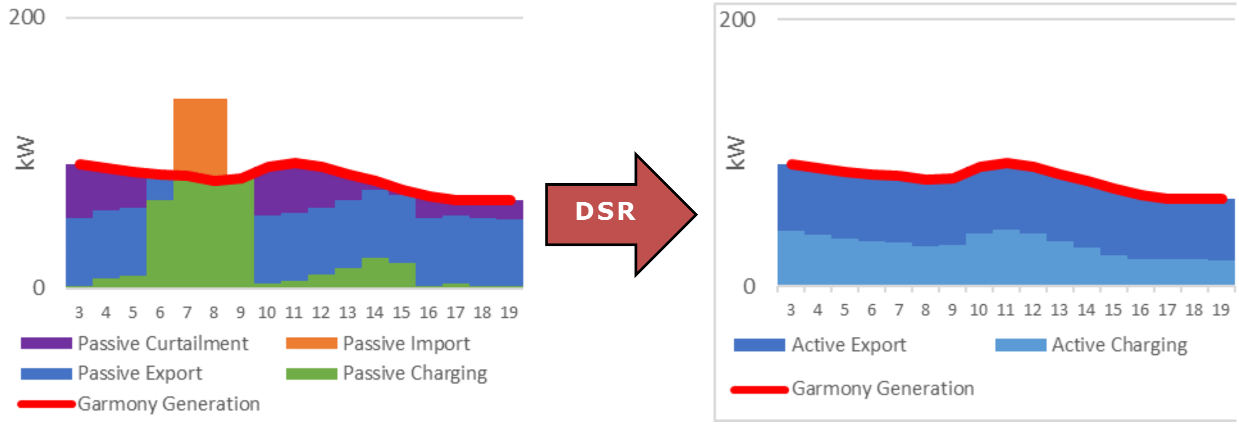

Figure 21 Flexible charging

Flexible charging, as shown in Figure 21, decreases import and curtailment (in orange and purple) and increases export (in blue). Curtailment can be mitigated both by local absorption and through better management of the available network capacity.

Below we present the total power import and export for the modelled scheme. Under forecast matching, the increase in power exported from Mull to the mainland —38MWh—comprises 70% of the avoided curtailment (54.4MWh).

Table 7 Forecast charging reduces imports and increases exports (results for Central Case)

	Baseline	Opportunistic Charging	Forecast Charging
Total Export (MWh)	535.0	535.0	573.4
Share of Generation Exported	55.7%	55.7%	59.7%
Imported Power (MWh)	404.9	391.8	378.7
Share of Island Demand met through Imported	55.1%	53.3%	51.5%

Management of electric heating to avoid curtailment of local generation therefore derives not only from absorption of over-supply but also shaping the total local demand profile to match real-time generator output and export constraint[22].

On this basis, a static time-of-use tariff will necessarily severely limit the ability of heaters to avoid curtailment.

- Avoided curtailment also reduces power imported, by 3% and 6% respectively. Reduced imports could also be monetised under particular commercial arrangements, for example suppliers may

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[22] Here we model a static export constraint although there is in principle no reason why a dynamic constraint could not also be matched.

lower their procurement costs by agreeing power purchase agreements (PPAs) at below market price with generators whose local demand they de-constrain at some fraction of market value, see section 6.c.

v. Reduction in resistive losses through avoided use of connection to mainland

Matching local generation and demand reduces the throughput and peak use of the connection to the mainland. The losses in this connector are mainly resistive losses that vary with the square of the current; local load matching to avoid curtailment and smooth out peaks in the import and export profiles should then also reduce interconnector losses.

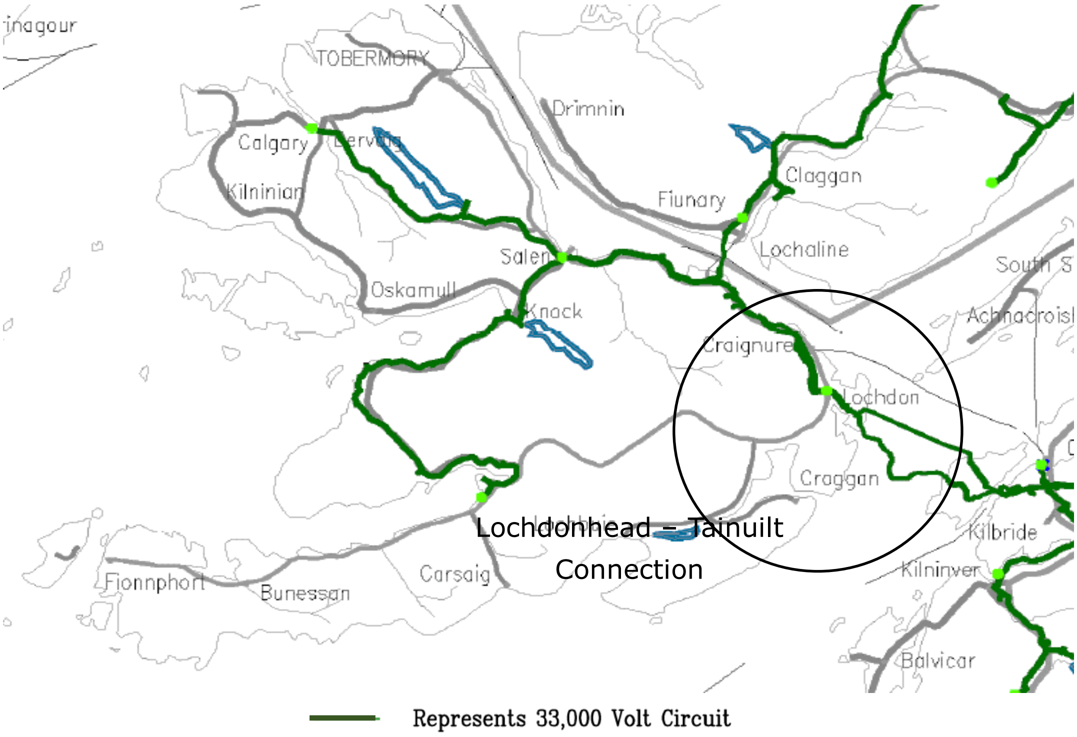

Figure 22 Distribution Network Connections to Mull

Based on the data in the SSE Long Term Detailed Statement[23], we estimate that the resistance across the 21.4km of the 33kV, three-phase interconnector is 2.4Ω. Given the high voltage level of the connection and the relatively modest amounts of electricity moved on and off the modelled scheme, the absolute power losses are modest. However, the conclusion that smart management of demand can reduce peak power flows and—in so doing—network losses, remains.

Table 8 Scaled Interconnector Losses Associated with Lochdonhead Interconnector (central scenario)

	Baseline	Opportunistic Charging	Forecast Charging
Resistive Losses (MWh)[24]	0.120	0.118	0.115
Scaled	100%	98%	96%

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[23] SSE Long Term Detailed Statement, table 1.

[24] This modelling does not take into account variation in resistance of the connecting cable due to resistive heating and considers the load on an hourly resolution. It may therefore in each case underestimate the losses.

b. ***Relevance to Other Renewable Generation Technologies***

Onshore wind is the cheapest means of generating electricity and is Scotland's leading renewable energy technology, with over 6.5GW installed at the end of 2016. Solar PV is the largest renewable generation technology in the UK, with nearly 12GW installed[25].

Table 9 UK Renewable Generation Technologies are dominated by onshore wind and solar PV

Technology	MW Installed
Onshore Wind	10,924
Offshore Wind	5,294
Shoreline wave / tidal	13
Solar photovoltaics (PV)	11,899
Small scale Hydro	358
Large scale Hydro	1,477
Landfill gas	1,062
Sewage sludge digestion	257
Energy from waste	1,017
Animal Biomass (non-AD)	129
Anaerobic Digestion	420
Plant Biomass 3	2,850
Total	35,700

Onshore wind and solar PV comprise over two-thirds of installed capacity of renewable generation in UK, with offshore wind making up most of the remainder. (Table 9)

Table 10 Central Levelised cost of Electricity (LCOE) for 2026

Technology	LCOE (p/kWh)
Onshore Wind	6.3
Large Scale PV	6.7
Hydro (500kW–2MW)	9.5
Offshore Wind	10.6
CCGT	6.6

Onshore wind and PV compete on price with closed cycle gas turbines (CCGT), the cheapest form of fossil fuel generation. River hydro is around 50% more expensive. (Table 10)

As wind and solar are therefore likely to represent a greater share of future installed renewables than river hydro, we investigate the ability of the systems like the ACCESS DSR platform to avoid curtailment for these generators. In modelling alternate projects, we constrain the generator to the same extent as the hydro plant so that results are comparable across technologies[27].

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[25] Energy Trends: renewables—GOV.UK

[26] BEIS - Electricity Generation Costs (November 2016)

[27] Data are taken from real life projects-rather than diversified system generation profiles.

Table 11 Export constraints and generator sizes

Generator	Low (5%) Constraint (kW/%)	Central (10%) Constraint (kW/%)	High (20%) Constraint (kW/%)
400kW Hydro	285 (72%)	240 (60%)	175 (44%)
344kW Wind	149 (43%)	113 (33%)	62 (18%)
464kW Solar	298 (64%)	251 (54%)	184 (40%)

The export constraints and generator sizes in Table 11 are specified to give the same generation and curtailment levels as in the previous section. Given the generation profiles, solar case export and nominal capacities are appreciably larger than the hydro and wind

The seasonal distribution of generation differs for these technologies compared to Garmony.

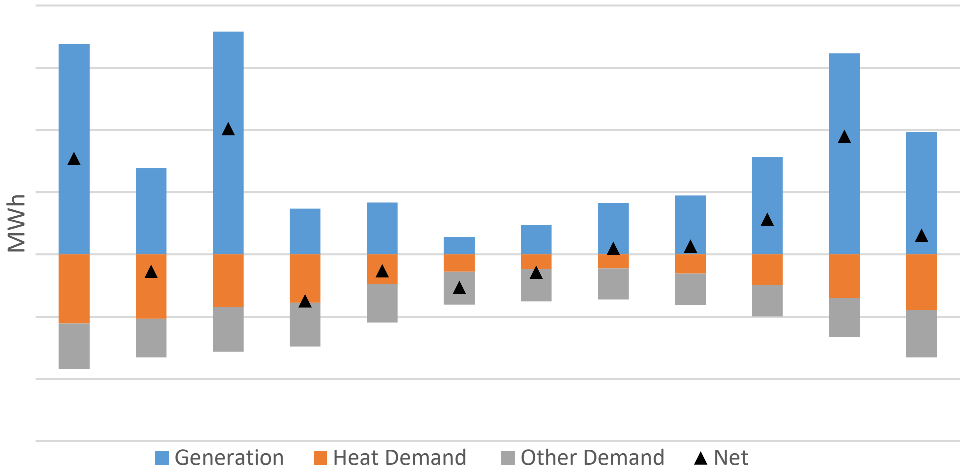

Figure 23 Wind Generation & demand

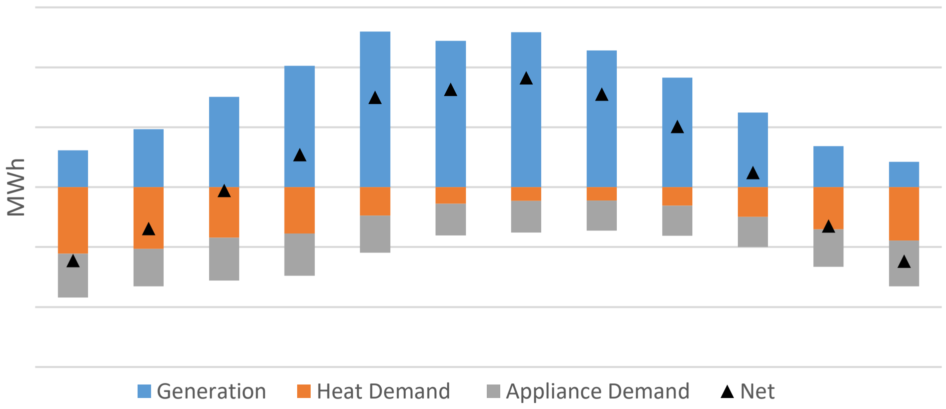

Figure 24 Solar Generation and demand

We find the ACCESS solution performs equably well at mitigating wind as hydro curtailment. Wind generation and ACCESS Scheme demand are well matched, (Figure 23) with both generation and demand concentrated in the winter whereas solar generation and ACCESS Scheme demand are negatively correlated by month (Figure 24). Passive storage heater demand is not well suited to reduce PV curtailment. Again, passive operation mitigates some curtailment but Forecast charging is around twice as effective and since their generation profiles and load factors are similar, curtailment of wind generation by charging algorithm is similar to the hydro case (Figure 25).

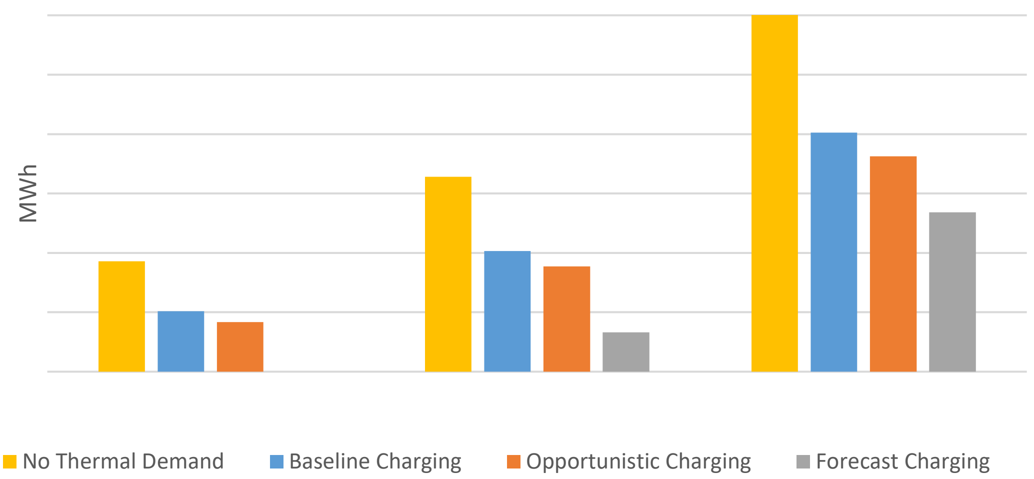

Figure 25 Curtailment of Wind Generation by charging algorithm

For solar PV, passive heating mitigates less curtailment than for other technologies as generation is distributed across summer day times and demand in the winter overnight. However, more surprisingly, smart management of storage heaters can reduce curtailment of solar PV by similar amounts as for the other generators[28].

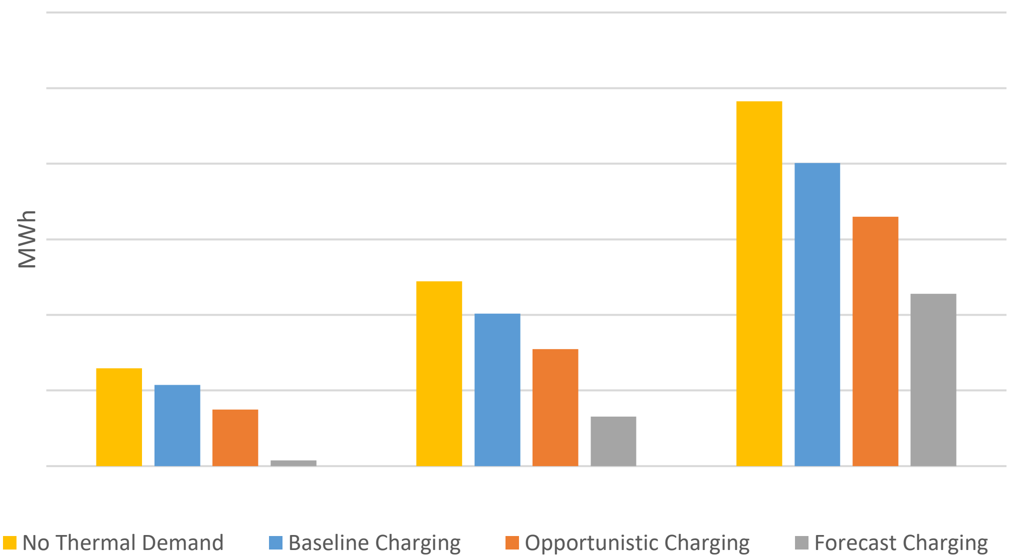

Figure 26 Curtailment of Mull Solar PV Generator

In the solar case, only one third of the smart avoided curtailment is due to increased export, as there is so little overlap between heater charging and solar generation during which export can be increased.

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[28] Note that the absolute export capacity for solar PV is higher, since the electricity is generated at a lower load factor.

Table 12: Import and Export for PV Matching Scenario (Central scenario)

	Baseline	Opportunistic Charging	Forecast Charging
Total Export (MWh)	565.0	565.0	588.1
Share of Generation Exported	58.9%	58.9%	61.3%
Imported Power (MWh)	441.3	417.9	396.4
Share of Island Demand met through Imported	60.0%	56.8%	53.9%

Demand management of storage heaters can therefore have a significant effect not only on curtailed hydro and wind generators but—more surprisingly—on PV generation.

The cost data are shown below; in place of the hydro FiT figure, we use 2.31p/kWh for wind and 5.03p/kWh for solar[29] .

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[29] Ofgem - Feed-In Tariff (FIT) rates

Table 13 Per Household Avoided Curtailment and associated Values and Costs, Wind

	Opportunistic			Forecast		
	Low	Central	High	Low	Central	High
Total generation value (PPA + FiT) (£)	0.15	0.21	0.33	0.83	1.12	1.3
Generation value excluding FiT (£)	£11.72	£16.40	£25.77	£64.82	£87.47	£100.02
Retail Bill Increase (£)	£8.3	£11.6	£18.0	£45.8	£61.5	£70.4
As share of Baseline Bill	£10.7	£15.1	£21.6	£133.4	£152.1	£181.8
Increase per Absorbed MWh	1.5%	2.1%	2.9%	18.2%	20.7%	24.7%
Net Generation Value (£) (FiT + PPA -Bill Increase)	£71.1	£71.6	£65.9	£160.0	£136.0	£142.0
Net Generation Value excluding FiT (£)	£1.02	£1.30	£4.17	-£68.58	-£64.63	-£81.78
Estimated System Value (£)[20]	-£2.40	-£3.50	-£3.60	-£87.60	-£90.60	-£111.36
Total generation value (PPA + FiT) (£)	£3.9	£5.5	£9.1	£11.7	£19.4	£21.9

Table 14 Per Household Avoided Curtailment and associated Values and Costs, Solar

	Opportunistic			Forecast		
	Low	Central	High	Low	Central	High
Total generation value (PPA + FiT) (£)	0.27	0.38	0.58	0.82	1.11	1.42
Generation value excluding FiT (£)	**£28.43**	**£40.01**	**£61.07**	**£86.35**	**£116.88**	**£149.53**
Retail Bill Increase (£)	£14.6	£21.1	£32.1	£44.9	£61.3	£77.8
As share of Baseline Bill	**£11.0**	**£16.5**	**£21.0**	**£130.1**	**£140.9**	**£150.1**
Increase per Absorbed MWh	1.5%	2.2%	2.9%	17.7%	19.2%	20.4%
Net Generation Value (£) (FiT + PPA -Bill Increase)	£41.2	£43.0	£36.0	£159.2	£126.5	£106.1
Net Generation Value excluding FiT (£)	**£17.43**	**£29.01**	**£40.07**	**-£43.75**	**-£13.22**	**-£0.57**
Estimated System Value (£)[20]	£3.60	£4.60	£11.10	-£85.20	-£79.60	-£72.30
Total generation value (PPA + FiT) (£)	**£7.4**	**£10.9**	**£19.8**	**£6.9**	**£17.5**	**£31.2**

We find:

- While the river hydro FiT rate makes it viable to pay local consumers to match demand, the lower subsidy for wind and PV schemes makes only modest load matching cost effective.
- In the solar case, there is significant room to improve on the baseline curtailment mitigation, for wind generation it is difficult to mitigate much oversupply without increasing consumer costs by more than the increase in generator revenues.

i. *Findings on Renewable Curtailment Avoidance*

Households can mitigate around 1MWh of curtailment of a marginally constrained generator through flexible, forecast charging over a year, or around 0.4MWh per year through turning up in response to available oversupply (compared to baseline operation); Forecast matching outperforms Opportunistic charging by a factor of 3. These results are stable across generation technologies.

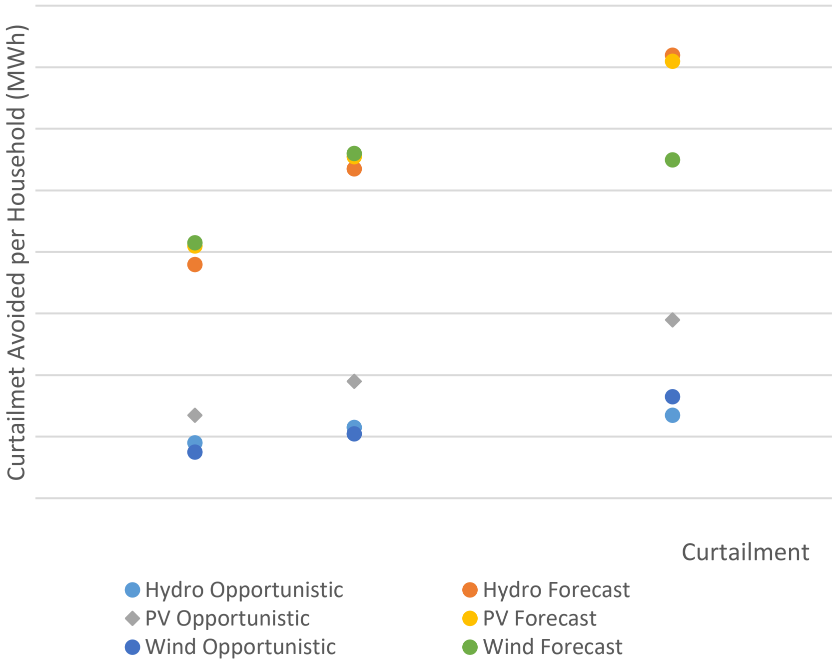

Figure 27 Avoided Curtailment

Opportunistic and Forecast Curtailment avoid similar levels of curtailment across generation technologies—around 0.4MWh and 1MWh respectively—compared with passive operation. (Figure 27)

Storage heaters cannot mitigate sustained over-supply but smart charging mitigates almost all curtailment during periods where net local demand meets or exceeds supply, both through absorbing over-supply and increasing export through smarter charge profiles.

However, under maximum demand flexibility each MWh of generation enabled increases existing average two-rate bills by over £100b. As such, maximum local demand matching on most two-rate tariffs destroys value without generous subsidy.

It may be possible to improve this figure by more sophisticated co-optimisation but it is apparent that constraints on current tariff charging patterns reduce the ability to de-constrain the network. A more structural solution would align the incentives of the necessary energy system participants to encourage, rather than penalise, absorption of local generation at peak times. These types of arrangements, such as local energy tariffs, are investigated in section 6.g but first, other potential revenue streams available for domestic DSR are considered below.

c. ***Opportunities for Service Provision***

Appendix H details the possibilities for offering this load flexibility as a service to the Electricity System Operator (ESO) and the local Distribution Service Operator (DSO). The Balancing Mechanisms that the ESO pays for to keep the voltages and frequency of the grid within the specified limits are changing and it is not possible at this stage to assess an accurate figure for the income possible from service provision to the ESO.

The DNOs are all recognising that they have an increasingly important role to play in balancing the grid and need to somehow move to fulfilling the role of Distribution Systems Operator (DSO). Again, it is currently unclear how the financial incentives that will be offered to flexible loads will be set and what levels of payment might be achievable.

What is clear, however, is that flexibility services will be in demand and revenue streams will become available for domestic customers as these markets develop and become established. Their value is likely to be around a hundred pounds a year or more depending on the type of flexibility, speed of response and location.

The following section uses the historic values discussed in Annex H.

d. *Revenue Stacking and Overall Value*

As in the previous section, the active management of heater charging to increase capacity can mitigate 1–2 MWh of marginally constrained generation a year (around a quarter of total thermal demand), partly through direct absorption and partly through optimisation of export capacity. The value of this generation is modelled above and the distribution of this value across participants is discussed in section 6.f. The wholesale value from the hydro central analysis (£25/year) is presented here as it is not affected by arbitrary decisions on subsidy or tariff structure.

Homes using storage heaters could earn up to £80 per year by optimising procurement from power markets without increasing their use-of-system charges. However, wholesale power costs associated with fully flexible charging are higher than those in the un-optimised passive case; it may be possible to buy de-constrained local generation at lower than market rates (see section 6.f), but optimisation of charging for low market prices and de-constraining local generation are likely to create opposing priorities. It is therefore likely not possible to fully exploit both revenue streams. As this analysis of price optimisation and BM revenues build on one another, it is possible to access these revenues simultaneously.

ACCESS households could earn over £250 by providing network regulation services to the ESO; around a third of their typical electric heating bill. Greater value may be possible through regulation services ideally suited to storage heater response.

Operational considerations or regulation may preclude offering capacity market and frequency response services through the same asset; one signal may require heaters not to operate, while the other requires them to turn up. It is therefore not assumed that both revenues can be accessed simultaneously, although National Grid ESO is currently increasing transparency and lowering barriers to service provision—it may in future be possible to access both revenue streams in some clear priority order.

Smart storage heater users could possibly reduce their heating bills by almost half, to levels equivalent to gas heating (on a per kWh basis). Table 15 shows a summary of the energy system revenue streams and values under frictionless commercial models.

Table 15 Summary of Energy System Revenue Streams and Values

Counterparty	Service	Value [£/Year]	As Share of Bill
Local Generators	Load Matching	£22[30]	3%
Power Markets	Price Optimisation	£67	9%
	Negotiation	£10	1%
ESO	BM participation	£67	9%

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[30] We present the wholesale value of curtailment avoided through Forecast matching a 10% constrained generator

	FR	£226	30%
	Capacity Market	£40	5%
	Demand Turn Up	£0	0%
Maximum Simultaneous Provision		**£392**	**52%**

i. Risks

The model under which storage heater manufacturers license control of their infrastructure is not yet clear; it may be that this absorbs a significant share of the above value.

Ability to provide frequency regulation services in winter is a function of heater headroom. Heaters installed in the ACCESS project show significant headroom; they may not have been subject to individual customer cost benefit considerations around the size and usage patterns of individual homes, or rooms therein and may therefore be unrepresentatively large for the heating demand. This would make the FR revenue values here overestimates but leave BM participation revenues and power price optimisation revenues unchanged.

e. ***Wider Implications***

i. System Balancing Services

300,000 homes in Scotland are heated using storage heaters; representing 2GW of capacity. The UK figures are 2.2m[31] and 18GW[32] respectively.

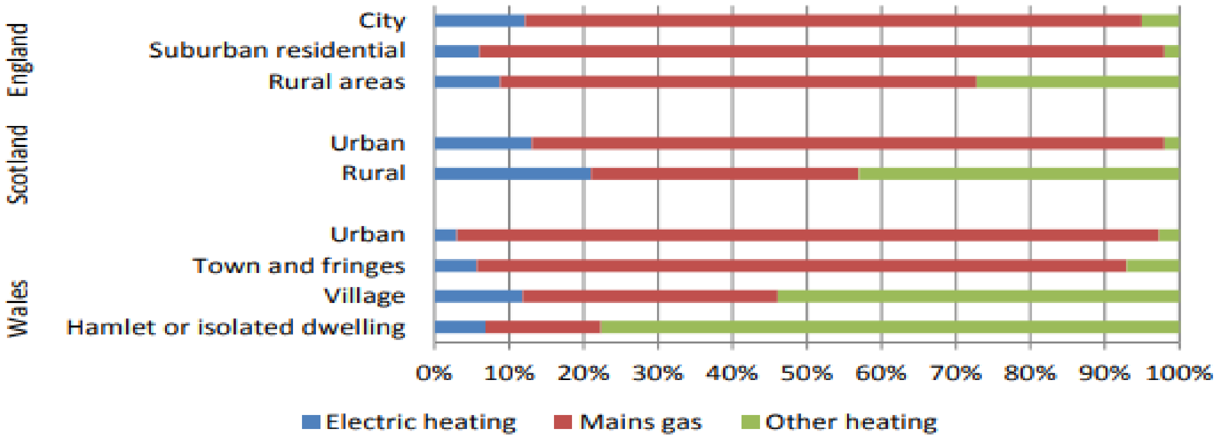

Figure 28 Main heating fuel by location in England, Scotland and Wales

Through active load control, all of these homes could access the system interaction revenues above, and in rural areas may also de-constrain renewable generation. The majority of DSR value is, however, created through provision of rapid response ancillary services.

ii. Extrapolation to Other Storage Heated Homes

DSR revenues for electric heating scale with heating demand, so similar proportion savings are possible across electrically heated homes. Absolute demand levels, however, vary significantly across electrically heated homes. The Scottish Housing Condition Survey (SHCS)[33] collects data on energy demand, fuel poverty and building condition across a representative range of homes in Scotland. The publicly available

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[31] Ofgem Insights paper on households with electric and other non-gas heating (2015)

[32] BEIS Domestic DSR Competition—Competition Guidance Notes

[33] The SHCS is "the largest single housing research project in Scotland, looking at the physical condition of Scotland's homes and the experiences of householders".

data covers total energy use; space heating—which comprises 70% of total demand—is not disaggregated.

SHCS data show that urban and rural homes differ significantly in their energy consumption; it is not clear to what extent rural homes meet their heating demand with secondary fuels (at least 14 of the 61 ACCESS participants use other heating fuels) but the absolute DSR values available to most electrically heated homes, especially rural homes heated solely using electricity, will be around twice those modelled above.

Household energy use data for rural and urban Scottish electrically heated homes, show consumption is nearly twice as high in rural as in urban homes. (Table 16)

Table 16 Scottish rural and urban energy for electrically heated homes

Area	Annual Energy Use (kWh)
Urban	13,769
Rural	25,293

iii. System Balancing Services

NG-procured volumes of high value services are considerably lower than the total capacity of storage heaters, even allowing that heaters can typically offer only 60% of their capacity for FR at any given time.

Table 17 Procured Volume of ESO Services

Service	Average Volume
Dynamic High FR	76 MW[34]
Capacity Market (DSR)	312 MW[35]
Balancing Mechanism	198 MWh Up or 323 MWh Down per settlement period

Over the next 12 months, the average procured volume of dynamic High FR is expected to be ca. 76MW. Although other products may be created through which electric heaters can provide ESO services, NG note in the Future of Balancing services roadmap[36]**Error! Bookmark not defined.**:

> *… as we procure different types of frequency response, particularly faster-acting products, the volume of the existing products that we are buying will likely reduce. We are working to understand the interaction between volumes of fast and slower-acting frequency response products and how to build these interactions into a sustainable market.*

On this basis, ancillary service provision will create value for a small number of domestic DSR early adopters.

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[34] FFR Market Information March 2018

[35] 2016 data, see note **Error! Bookmark not defined.**

[36] National Grid—Future of Balancing Services Roadmap

iv. Implications for Fuel Poverty

Given the very limited volume of high value service provision, most smart storage heaters will create value only through price optimisation[37] services (which are not constrained by volume of provision) and possibly BM participation. Together, these are worth less than £150/year to ACCESS participants. Provision of grid services does not therefore represent a system-wide solution to lowering the cost of heating in these homes by more than 20%.

Where tariffs efficiently reflect system value, it is likely that the total value available through matching local demand does not exceed £50—less than 10% of the bill—available only to homes in rural areas served by constrained grids with abundant renewable resource. The control priorities of system price optimisation and matching local generation may also interfere, so it may not be possible to create maximum user value through these two services simultaneously.

As space heating accounts for around 70% of the energy costs of a Scottish home, the ACCESS solution might allow a 15% reduction in energy costs. The effect of such a saving on the distribution of homes in fuel poverty is shown below.

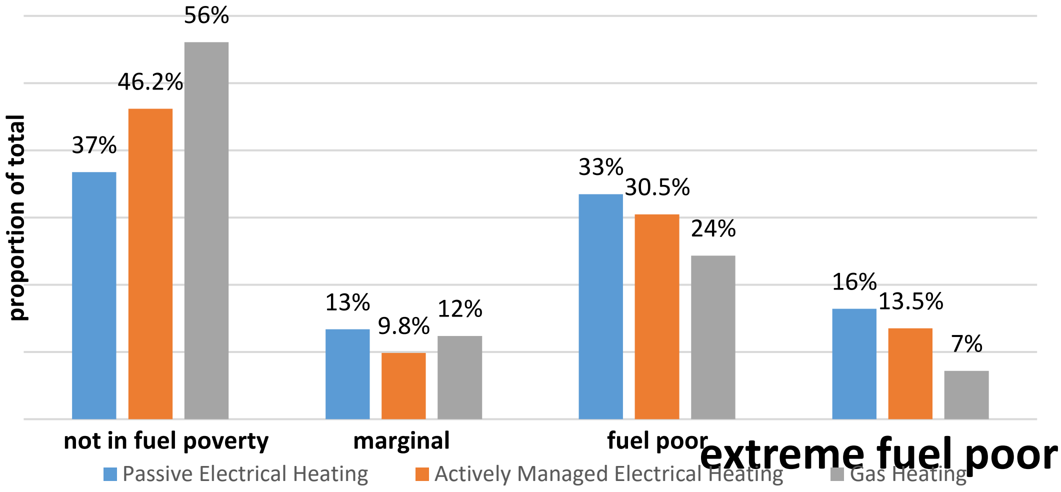

Figure 29 Active management of electric heating can reduce Fuel Poverty

As the data in Figure 29 shows, the active management of electric heating can indeed reduce Fuel Poverty but marginally and not to the level of gas heated homes[38]

40% of Scottish electrically heated homes are social housing, over half of which are in fuel poverty.

Table 18 Distribution of electrically heated homes by occupancy

	LA/ Other public	**HA/Co-op**	**Owner-occupied**	**Private-rented**
Not In Fuel Poverty(<8% Spent on Energy)	6%	7%	17%	8%
Marginal Fuel Poverty (8–10%)	3%	3%	6%	2%
Fuel poor (10–20%)	8%	8%	13%	5%
Extreme fuel poverty (20%+)	3%	2%	9%	3%
Total	19%	19%	45%	17%

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[37] Simultaneous price optimised of 15GW of demand will clearly move the market, making it difficult to estimate how this will affect prices. Such considerations are beyond the scope of this analysis.

[38] SCHS data. Note that this data does not differentiate between electrical and gas use totals and cost, or homes operating storage and panel heaters.

The table of proportions of electrically heated homes by occupancy and fuel poverty status shows social and local authority housing having the lowest proportions not in fuel poverty (Table 18).

Social landlords or cooperatives are often responsible for the provision of heating infrastructure and in some cases bill payment, so this heating demand may constitute a cluster of demand that is simpler to connect to an aggregator than individual, privately-owned homes.

f. *Potential business models*

In the previous sections, it was found that the extent to which demand can be matched to local generators may be constrained by customer bills (unless the power attracts a generous subsidy), and the value associated with providing services to the ESO, most of which require an aggregator to manage a portfolio of consumer demand, was estimated. In this section, how the various parties might interact is examined, along with which revenues they could then access and how consumer bills could be lowered, while at the same time increasing constrained network capacity for renewable generation.

A simplified structure of current domestic power billing and settlement and network operation and monitoring, is shown below (Figure 30). Domestic customers engage only with their supplier. Suppliers compete to attract customers by creating lower tariffs, which reflect the costs to which they are exposed through a (possibly variable) unit price (in p/kWh) and a standing charge (in p/day). These tariffs are subject to substantial regulation.

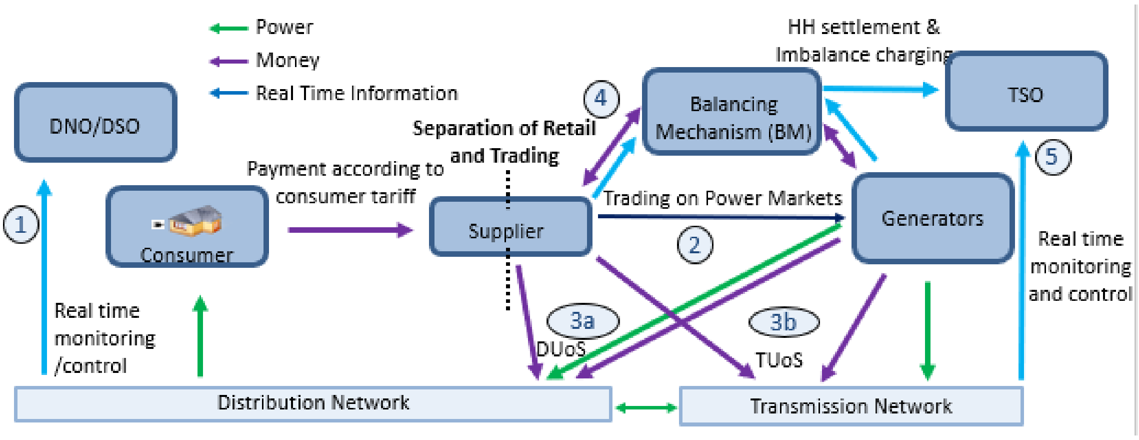

Figure 30 Domestic customers engage only with their supplier

1. Domestic customers connect to the largely unmonitored LV network (sub 1kV). Most HV and EHV sections of DN are monitored in real time but reactive control of connected generators is limited to a small number of ANM zones.
2. Generators sell their power to suppliers (generators cannot sell to customers) on the future or spot power markets (explained further in appendix E).
3. Suppliers pay the Distribution Use of System (DUoS) charges of their domestic customers, which are charged on a flat or two tier rate, though this will change following the introduction of domestic half hourly metering. Sub 100MW generators do not pay transmission use of system (TUoS) charges, while suppliers' TUoS charges are based on the net power taken off or put on the high voltage transmission system.
4. Suppliers' positions for domestic demand are settled roughly each quarter, with several months' meter readings binned into half-hourly settlement (HHS) periods following the Elexon 1 and 2 Profile Classes. This may also move to HHS following introduction of smart meters. Parties' imbalance is charged or reimbursed at the SSP or SBP (see appendix E).
5. ESO procures real time grid regulation services through auctions and bilateral contracts and operates the Balancing Mechanism which ensures that supply matches demand and determines the system buy and sell prices.

Above, the value available through provision of the following services was calculated:

Table 19 Revenue Streams Available through Domestic DSR

#	Beneficiary	Can Use DSR to:	Value per ACCESS Household (£/year)
1	Suppliers	Move demand to minimum price settlement periods (following HHS)	£70
2		Optimise their power purchase strategy	£10
3		Move demand to minimise use-of-system charges.	£60
4	Generators	Increase instantaneous and long term export capacity.	Around £25 but depends on the degree of generator(s) constraint
5	Balancing Mechanism	Reduce generation/demand imbalances	£70
6	DNO/DSO	Avoid network reinforcement as Low Carbon Transport is added to the network.	Depends on DNO requirements and constraint
7	ESO	Balance network or provide capacity though services such as FR, Reserve and reactive power.	£250

Four commercial models are now considered, through which these revenue streams can be accessed:

i. Candidate Commercial Arrangements for Domestic DSR

A. Generator contracts with Aggregator

The most obvious DSR arrangement is for the constrained generator to contract with an aggregator, using domestic load to mitigate curtailment and reimbursing customers for any increases in their bills (relative to an agreed baseline).

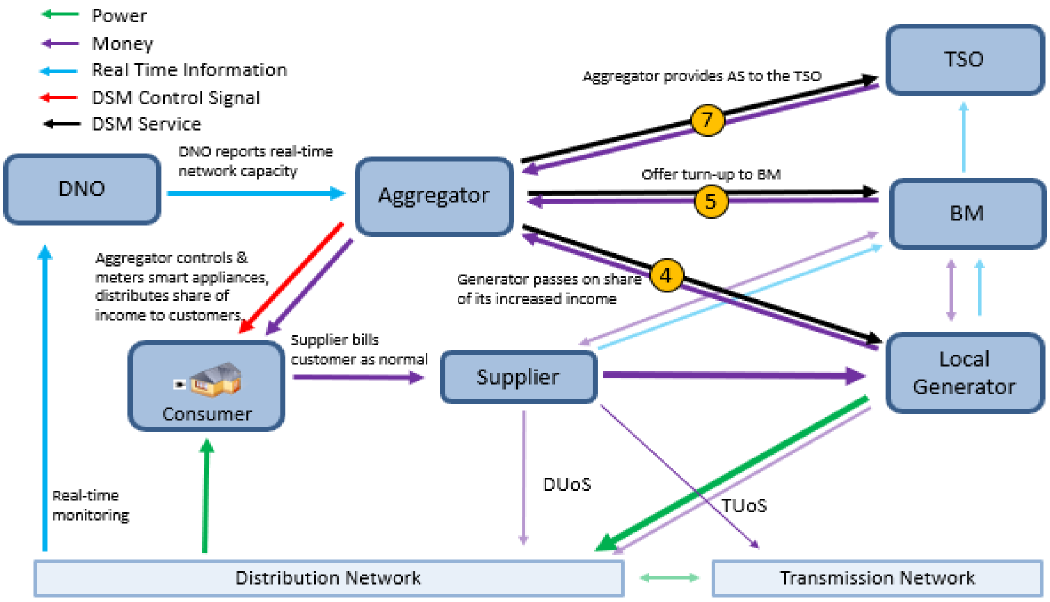

Figure 31   Commercial Model 1

Under Commercial Model 1 (Figure 31), generator(s) pay an aggregator to increase local demand, in response to real time data from the DNO, who plays no further role. Under this arrangement, network constraints are avoided and increased generation can be sold to the market.

- Generator pays the aggregator for load matching service, which reduces curtailment, allowing more power to be sold. Generators do not necessarily sell their power to the supplier(s) of participating smart heaters.
- Suppliers buy generation as in the unmanaged scenario at marginal wholesale cost for each settlement period. Buying additional local generation will reduce their TUoS; which slightly incentivises their participation in this scheme. However, demand from DSR load may be hard to forecast, or change after gate closure, increasing the risk of being out of balance on BM. Suppliers are therefore likely to be neutral on this arrangement.
- Customer is billed as usual for their energy use by their supplier; this arrangement is unchanged. Their load is controlled by the aggregator, who pays a rebate for participation which (at a minimum) covers any bill increases associated with any charging moved into higher tariff periods. As above, at maximal use of flexible load for matching this may represent most of, or more than, generation value.
- The aggregator assesses and rewards compliance based on customer charging data (this does not require HH metering; it could be determined by aggregator’s record of smart device consumption).
- Aggregators could also provide ancillary services to the ESO or turn up to the BM from an FPN of zero. (FFR services are not checked through metering but BM participation may require HH or sub HH readings).
- The DNO takes no role in the value stream but reports network headroom, or eg, seasonal thermal network capacity constraint, in real time.

Table 20 Strengths and Weaknesses of Model 1

Strengths	Weaknesses
Simple to implement, requiring only bilateral agreement between generator-aggregator and aggregator-consumer and a network headroom data feed from the DN.	Under current 2-tier ToU tariffs, bill increases (for demand moved from off-peak to peak hours) may be greater than value of generation, limiting the volume of curtailment avoidance.
Allows many suppliers to participate.	Does not share flexible demand to increase network renewable connection capacity.
Does not require half-hourly metering or settlement.	BM position of supplier can be changed by aggregator following gate closure.
Compatible with current regulation and settlement model	No reduction in customer bill or supplier UoS per customer MPAN.

Under this arrangement, one generator may control all local flexible demand, precluding other generators from connecting. A top-down scheme, in which this load may be shared to maximise network renewable connection capacity, is therefore considered here.

B. DNO uses DSM to operate (part of) an ANM Zone

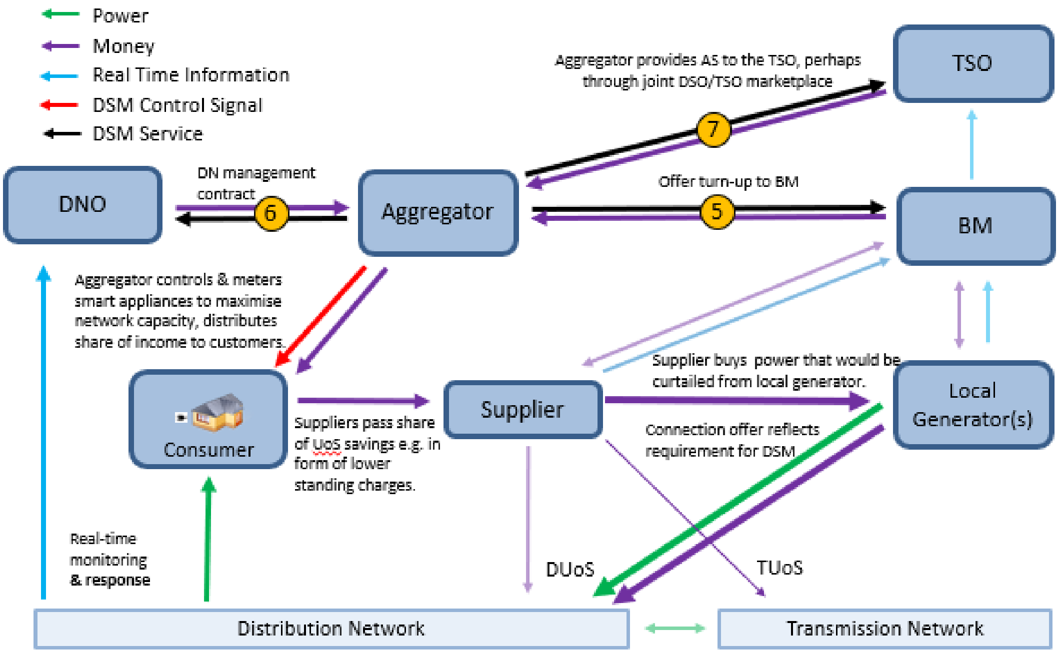

Figure 32 Commercial Model 2

In Commercial Model 2 (Figure 32), the DSO—now an active participant charged with maximising renewable generation on network—procures load-matching as an ANM service Under this arrangement, the DNO (as DSO) engages aggregator(s) to control load; increasing network ability to connect and absorb renewable generation. All generators connecting to the constrained network pay higher UoS fees that covers DSR service costs:

- DNO moves to a DSO role, taking responsibility for maximising network renewable connection capacity. As in previous example DNO would likely require a fail-safe generator curtailment option for each generator.
- Generators accept managed network connection offers, under which they contribute to cost of DSR, eg, through reduced GDUoS rates for generation that is load matched.

- In order to provide ancillary services or operate on the BM, DNO would need to allow aggregators to act autonomously, or move to an integrated ESO/DSO service provision model proposed in the ENA Open Networks work. In the former case, demand control priority would need to be clearly determined, given that the primary use case of the demand limits its capacity to move away from scheduled charging.
- The relationship between customers and suppliers does not change but, unlike above, customers may need to move to half hourly metering to satisfy DNO performance validation requirements.
- DNOs could create lower DUoS tariffs for scheme participants, incentivising suppliers (who pay customer DUoS charges) to move customers to this tariff by offering lower fees.

Table 21 Strengths and Weaknesses of Model 2

Strengths	**Weaknesses**
Top down solution maximises network capacity to absorb generation, creates (some) value for consumers and is (at worst) value neutral for DNO/DSO.	Requires DNO to move to active network management provision. It may be difficult to create a single regulation set appropriate to all DN zones How to share DSR capacity across new and existing generators equitably is not clear. May be simpler to implement for large industrial and commercial (I&C) customers, who have a direct relationship with their DNO and are exposed to half hourly power prices.
Some reduction in customer costs achieved through DNO creation of bespoke DUoS schedule to which suppliers encourage electrically heated homes to move.	As above, the requirement that increased consumer bills not exceed generation value limits available matching volumes.

These two models do not avoid the problem that even if DSR creates value for consumers through ESO services, unsubsidised generators pay more to cover maximum load matching than they earn from increased power sales. This is a result of tariff structures, which do not efficiently reflect variation in the supplier’s costs.

Two means of enabling alternative tariff structures, by bringing the supplier into the scheme, are investigated here.

C. Demand and Generation are Net-Metered as Single Virtual Unit

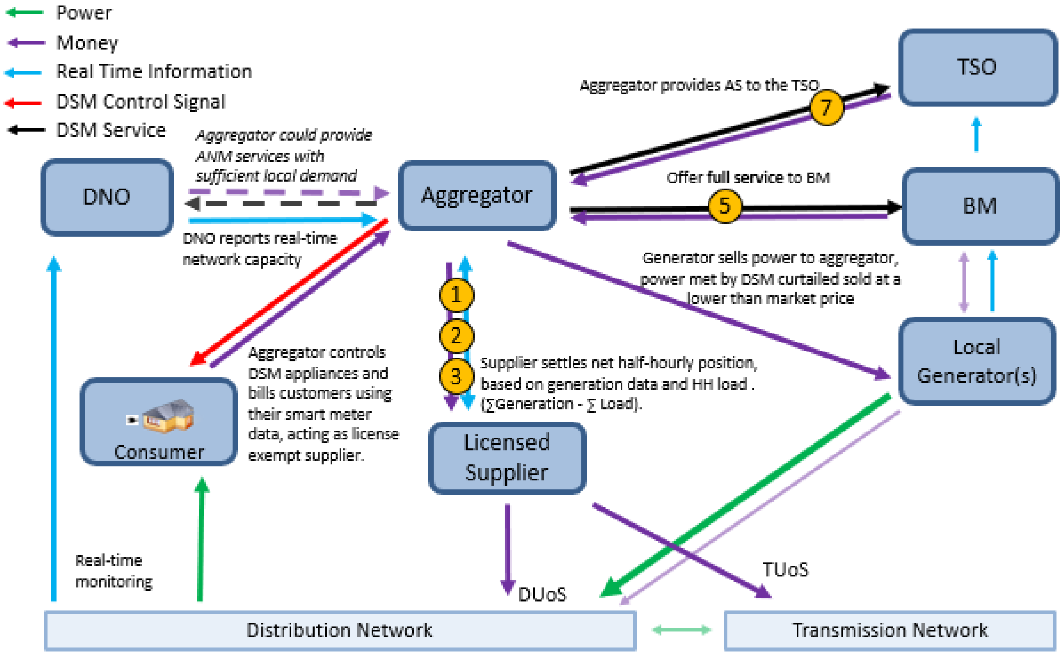

Figure 33 Commercial Model 3

In Commercial Model 3 (Figure 33), a virtual network aggregates (smart) demand and generation behind a single MPAN or BMU, using a Licence Exempt (LE) supply. Under this model, a bespoke local arrangement creates a single virtual energy system unit, comprising managed demand (or all demand of managed households) and any constrained generators. This structure is enabled through a virtual private network, with the aggregator matching the latter to the former and settling any net power import or export with a licensed supply partner half hourly. Under this model, the aggregator is able to access all revenue streams[39], including services to the DNO (provided they control sufficient participating demand in an ANM zone).

- The aggregator acts as a licence-exempt suppler for participating consumers and aggregates their demand with the scheme generation behind a virtual energy system unit. The net position is settled half hourly by the licensed supplier. The aggregator may settle the smart load only (customer settles appliance demand with their existing supplier) or all load[40] (customer changes supplier).
- The generator enters into an agreement with the aggregator to sell generation enabled through load matching to the aggregator at below-market price. This can be offered to new or existing plant.
- The customer is billed by the aggregator under a tariff that incentivises participation in DSR (HHS is likely required for market settlement but bills need not be half hourly).
- Consumers' and generators' DUoS charges can remain unchanged, based on (real) MPANs. Alternatively the DNO may contract with the aggregator for provision of network benefits, provided the aggregator can offer sufficient flexible load and encourage participation through a bespoke DUoS schedule.

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[39] Where multiple revenue streams are accessed, careful co-optimisation of the revenue streams will be necessary.

[40] Both arrangements have technical and regulatory considerations; the former requires the supplier to subtract HH managed demand from consumer bills according to a bespoke agreement with the aggregator and to allow two parties to bill the consumer for parts of their bill. The latter is simpler but requires all demand to be HHM.

Table 22 Strengths and Weaknesses of Model 3

Strengths	**Weaknesses**
Flexible tariff means customers are incentivised to move their demand.	Customer UoS tariffs may be static or not reflect local network, so DNOs cannot use price signals to affect DSR consumption patterns.
No barriers to entry if Virtual MPAN and license exempt supply are made to work.	There is little track record of virtual private wire and individual DNOs or DNO zones may require different solutions.
Tariff and customer and generator proposition can simply be made locally specific.	Consumers can switch supply arrangements at 28 days' notice. Consumer debt and imbalance charge risk sit with aggregator.
Full range of revenue streams, including price optimisation, can be accessed.	No obvious benefit to this structure over traditional supplier HHM of (smart) customer demand.

There is little track record of license exempt supply or virtual private wire. A model is therefore considered that builds on established supply arrangements.

D. Supplier Creates DSM Tariff, uses demand to enable and buy local generation at below market price.

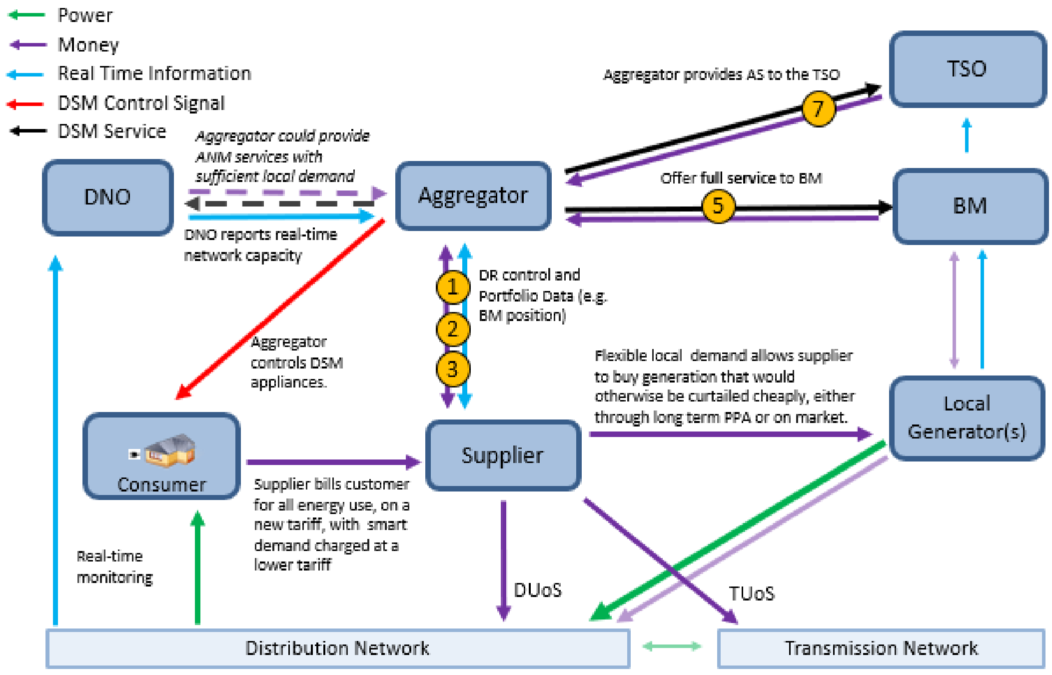

Figure 34 Commercial Model 4

Under Commercial Model 4 (Figure 34), the supplier offers a new, possibly local, tariff for DSR-enabled load and contracts with an aggregator to manage this demand. The supplier creates a specific DSR tariff; customers allow their load to be controlled in return for cheaper energy, and the aggregator matches this demand to local supply. This enables suppliers to procure generation cheaply from de-constrained local renewables.

Under this arrangement:

- Supplier creates a DSR tariff, which creates a portfolio of flexible load. It creates value through the ability to de-constrain and then buy power that would otherwise be curtailed at below market prices. The tariff could also allow the optimisation of heater charging to the spot market.
- The aggregator optimises the supplier portfolio as a service and/or pays the supplier a share of the value from DNO/ESO regulation services (if several revenue streams are accessed, careful co-optimisation will again be required).
- Participating customers allow direct control of their load by the aggregator in exchange for reduced bills.
- As in the previous case, there is no requirement for DNO engagement, though they may procure network management services from the scheme.

Table 23 Strengths and Weaknesses of Model 4

Strengths	**Weaknesses**
Allows creation of tariffs that maximise capability to provide a range of services to generators, ESO, DSOs and BM.	Does not necessarily reflect network operators' priorities.
Highly scalable	Risk of customers switching supplier; competing suppliers may create similar tariffs and then attempt to attract the same flexible load.
Signal can incorporate DNO signals as well as local and system generation prices.	Fails to provide clear target to generators looking to connect to the network.

ii. Findings

It can be seen that the majority of domestic DSR revenue streams are available in each case, particularly the ESO services, which represent most of the available value. However, given their limited volume, this study focuses on considerations for renewable generation connecting or connected to a constrained network branch.

The first model does not include the supplier, therefore suppliers have little interest in encouraging users to join the DSR scheme and do not reduce customer tariffs. Generation absorbed is therefore limited by the distribution and peak/off-peak price difference of these tariffs, which do not respond to the local network situation.

The second model improves on this situation, as supplier costs can be reduced by a tailored DUoS schedule. More significantly, it maximises the use of DSR for network capacity increase and provides a clearer proposition to generators as part of their (non-firm) connection offer from the DNO, rather than accepting a connection under which they may be curtailed and creating a parallel DSR agreement with an aggregator.

The third and fourth models create a supplier interest in de-constraining the grid by allowing them to buy avoided curtailment at below market prices. They are, however, subject to the risk that users with flexible load switch to alternative providers at short notice, particularly if suppliers compete to secure flexible local demand. If this uncertainty prevents renewable developers signing long term PPAs with suppliers, the fourth model will not increase networks' ability to connect renewables to the same extent as the second.

It is noted that an efficient, frictionless arrangement on a highly constrained rural network branch might create up to £50/household/year of local value through avoided curtailment, to be shared between generators, suppliers, aggregators and customers.

It is considered below how a consumer tariff might be structured to reflect the above benefits and create a clear proposition to attract customers.

g. ***Tariff Design***

The analysis above suggests that greatest domestic DSR value is created through supplier-led arrangements that can use controlled load to de-constrain local generators. As domestic customers can now be billed and settled half hourly and smart meter rollout is due to be completed by the end of 2021, it will soon be straightforward to record and reward domestic DSR.

Participating households could then be billed on a tariff that:

- transparently reflects value to participating customers and
- incentivises other owners of smart heaters to join the scheme.

In this section, current and candidate tariffs are reviewed, and recommendations made on a structure to provide a clear offer to customers that does not adversely affect any demographic, particularly vulnerable customers. As provision of frequency response requires heaters to be controlled on a second-to-second basis and direct load control is the preferred consumer DSR option, particularly for overnight device operation with no effect on home temperature[47], this review considers the billing arrangements under which direct control of smart devices is incentivised, rather that ToU tariffs as a DSR solution in their own right. In particular, the effect of tariff design on the following is considered:

- customer proposition,
- ability to reward behaviour, and
- risk of bill increases for vulnerable groups.

i. Current Arrangements

While there are currently no commercial direct-control tariffs for domestic demand, some suppliers have begun to offer tariffs which reflect some time-of-use variation in power price to smart-metered homes (many homes are unlikely to be able to access these arrangements before 2020. The smart meter rollout is ongoing and fewer than 20% of households have been fitted with smart meters)[41,42].

These tariffs fall into two broad categories:

- Static, under which customers are charged under two or more rates for their electricity according to a fixed schedule and
- Dynamic, under which the rates paid by residential customers for electricity varies (half) hourly, in a pattern that can change from day to day.

Current examples include:

- Green Energy's Tide[43] tariff is a static ToU tariff, with a low rate of 6.41p/kWh and a high rate of 30p/kWh.

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[41] Ofgem-Distributional Impact Of Time Of Use Tariffs

[42] Smart Meters statistics

[43] https://www.greenenergyuk.com/Tide

- Octopus' Agile[44] tariff, a dynamic ToU tariff. Prices are updated and communicated to customers on a day-ahead basis, a feature which may make planning more difficult for pre-payment or fuel poor households. Prices are negative at times and are capped at 35p/kWh[45].

As above, the wholesale power cost difference between a fixed annual and daily optimal charge pattern is around 35%; under a dynamic tariff this difference could be communicated to households[46]. However, the literature on consumer preference indicates:

> *Static ToU tariffs are consistently favoured over dynamic ToU tariffs[41]*

although this difference is small and reduced by automation of DR; it may therefore be mitigated by combination with DLC[47]. Also, while most literature on consumer attitudes to DSR does not consider electrically heated or Economy 7 homes as a distinct demographic, the Smart Energy surveys[47] found that:

> *Existing ToU tariff customers are more likely to report being interested in signing up to a static ToU tariff than the general population*

And that this group has a more developed than average understanding of the costs associated with their energy use patterns.

Table 24 Comparison of static and dynamic tariffs

	Advantages	**Disadvantages**
Static	Simpler to understand and plan for Preferred by customers	Does not fully reflect market reality to customers
Dynamic	More efficient than static Automation can reduce customer aversion to dynamic pricing, particularly for more engaged Economy 7 customers	More difficult for customers to understand More difficult to plan for with pre-payment or tight budgets

ii. Effect on Vulnerable Consumers

Ofgem considered the effect of moving to time of use tariffs; where underlying costs of energy and network use remain unchanged, most costumers reduce their bills by switching to a ToU tariff through moving demand away from peak times.

These findings hold across vulnerable households, with average bills falling, though these households may need to be offered greater savings to persuade them to change supplier, may be less than averagely engaged in their energy supply arrangements, and may need the regulator to protect those households whose bills may increase.

> *Vulnerable customers are generally less engaged in energy purchase, which means they are less likely to make explicit choices but rather remain with their existing arrangements. Many vulnerable customers would be better off on ToU tariffs but they may need targeted support to make that choice.*

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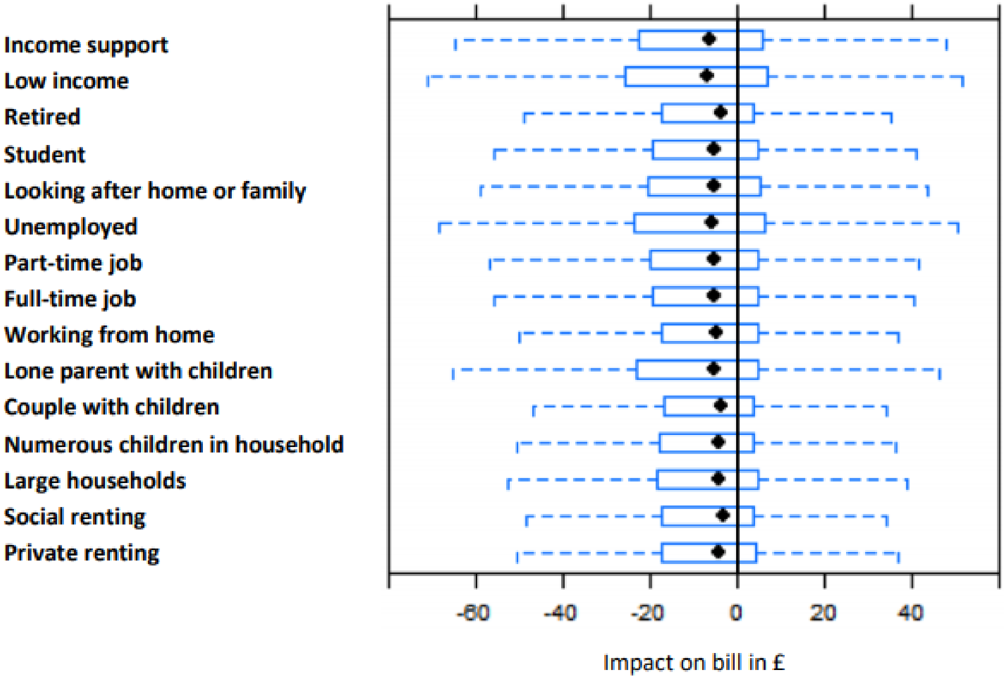
[44] https://octopus.energy/agile/

[45] Under both tariffs, risk of very high prices is therefore accepted by the supplier; 2016 spot prices exceeded these tariff maxima for 19 and 12 half hourly settlement periods respectively

[46] This analysis is based on spot, rather than day ahead prices; the variation for the latter may be smaller.

> *Others would be worse off and thus may need protecting from making that choice… Those vulnerable customers who have a higher than average peak demand, that they cannot reduce sufficiently, will continue to be better off on a flat rate tariff but would see bills rise relative to others as cross-subsidies unwind. There is a question surrounding whether protection measures may need to be put in place to protect this class of customer.*



Key: Dot shows median, Box shows interquartile, Bars show 2nd to 98th percentiles

Figure 35 Effect of moving to static ToU tariff

The effect on the annual bill of moving to static ToU tariff (including price response) is shown in Figure 35. Most vulnerable customers do better with a static tariff although there is much variation. (Black Dot shows median, Box shows interquartile, Bars show 2nd to 98th percentiles[41])

The Ofgem analysis assumes:

> *if consumers do not change their consumption, the bill of the average customer will remain unchanged relative to what they would have paid under an existing flat tariff*

whereas by allowing control of their demand, users create positive value. Suppliers may use this value to mitigate any bill increases, perhaps guaranteeing that no existing customer's appliance and heater use totals would cost more under the DSR tariff.

iii. Candidate Mechanisms

Following discussion with suppliers and aggregators, three half-hourly settled tariffs are presented, under which suppliers might bill consumers who allow direct control of their demand.

1. Flat Rate Tariff—under which all electrical consumption is charged at a single rate, which reflects the value created through price optimisation and service provision of smart load. It does not differentiate between managed and unmanaged demand but is simplest to understand and creates an incentive to allow load control of smart devices.
2. Two Rate Tariff—under which managed and passive devices are metered separately and charged at different (flat) rates. This allows the supplier to reflect the true value of flexible demand whose consumption can be optimised and used to provide system services, while appliance load

is charged on a higher rate tariff that covers the additional supplier costs across all participating homes. This tariff does not reward time management of non-smart load (which represent less than one third of total use for electrically heated homes) but is simple to understand, particularly for Economy 7 users.

3. Dynamic Time of Use Tariff—under which users are charged a price that varies throughout the day. Based on current tariffs, this might be the day ahead half hourly supplier cost of power delivery and include a margin and/or standing charge to cover operating costs, environmental levies, etc.

As above, these tariffs are assessed on their ability to:

- Incentivise participation through a clear customer proposition.
- Reflect to customers the value of the management of their demand.
- Protect demographic sub-groups, especially vulnerable users.

Table 25 Comparison of tariff types

Requirement	Direct Load Control Flat Rate	Direct Load Control Two Rate Tariff	Direct Load Control ToU Price
Clear Proposition	Customer views on participation in energy markets show a strong preference for simplicity and minimising engagement; a 2,000 respondent survey on tariff arrangements found "The most popular … was one involving direct load control (allowing electricity suppliers to cycle people's heating systems off and on in return for a lower flat rate)".[47]	Distinction into smart and passive categories, which replace the "low" and "normal" which currently differentiate between heat and power. "People who were currently on a 'legacy' time of use tariff (such as Economy 7) were consistently more likely to say they would switch to the next-generation static time of use tariff than the general population."[47]	Customer bill driven by supplier power procurement strategy; optimising competing options would be complex. "Static ToU tariffs are consistently found to be favoured over dynamic ToU tariffs" As prices are advertised 24 hours ahead, prepayment may be difficult to budget for.
Reflects value of individual choices	No incentive to move demand from passive charging to smart circuit.	Rewards customers for replacing passive appliances with smart versions. Does not reward turndown of appliances at times of high demand but this represents only 25% of total demand.	Rewards all demand that is moved away from times of higher prices efficiently.
Safeguards vulnerable customers	Depending on the values accessed by the scheme operator, the flat tariff rate may be higher than the passive charging low (heat) cost. On this basis, the tariff has the potential to increase the heating bill of some consumers.	Costumers could be guaranteed their smart bill components would not be higher than under their two-rate tariff.	Many customers are not comfortable with dynamic ToU tariffs "Approximately 50% of energy bill payers failed to identify the cheapest tariff, despite being given all the necessary information."[48]. Consumers may therefore not manage appliance demand appropriately at times of very high prices.

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[47] Consumers and Time of Use Tariffs

[48] Multiple behavioural biases create challenges for 'nudge': evidence from British energy bill payers

Metering of managed smart load and appliance demand on separate fixed tariffs then appears to represent the best approach to simply and fairly rewarding direct load control; corresponding roughly to heat and power respectively (the former would include all managed appliances, eg, smart washing machines, though smart appliances which are not load-controlled would still be charged on the "power" tariff[49]). More significantly, this tariff would also extend naturally to include managed home EV-charging on the "heat" tariff.

On this tariff, settlement would be half-hourly through smart meter data, while billing would require managed and unmanaged demand to be recorded separately, either:

1. On physically distinct circuits, or
2. Through smart devices recording their own charging, which is then subtracted from total demand on a half hourly basis.

The former solution is clearly infrastructure intensive, requiring rewiring of participating homes, and may be open to tampering. The latter is simpler but requires the supplier to ensure compliance of user smart devices, and to provide homeowners with a smart meter capable of this functionality (current smart meters do not in general include this).

It is noted that the entire customer demand is settled half hourly by their supplier; any smart devices are not involved in this process and so do not need to meet the accuracy requirements or other regulatory benchmarks (eg, SMETS compliance) to which smart meters themselves are subject.

As above, local considerations could inform tariff design and suppliers can create locally-specific tariffs. The degree of competition between suppliers for local renewable generation on weak grids may drive the extent to which they offer:

- a single, highly scalable, smart electric-heating tariff, or
- a range of local supply arrangements specific to a particular set of network constraints and generators.

h. ***Regulatory impacts***

i. DNO Involvement in Driving Domestic DSR

Much of the value of the domestic DSR requires DNO involvement or even coordination. While DNOs are increasingly taking an active role in the management of their networks and connections, their operation is prescribed by significant regulation, and DNOs may not innovate to link their embedded generation connection offer process and domestic DSR (the model 2 solution above) without significant regulatory encouragement.

However, the 2016 Customer Led Network Revolution (CLNR) report on domestic DSR collated the responses of several energy system participants, and concluded:

> *… the present [ED1 RIIO, covering 2015–2023] regulatory regime does encourage DNOs to do the right thing and provide solutions which are the most efficient overall[50].*

The report goes on to propose a detailed procedure for DNOs in identifying, categorising and addressing network constraint through DSR tender, which is compliant with current regulatory models and more cost effective than traditional solutions for complex network constraints.

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[49] This tariff could include an appliance charge ToU price variant for users who are highly engaged with their energy prices, allowing them to reduce their wholesale energy costs and system use charges by moving unmanaged appliance use to times of low system demand.

[50] CLNR Closedown Report

On this basis, the regulatory overhaul required for DNOs to drive domestic DSR management for networks appears modest. However, in areas where DNOs find traditional solutions more cost effective than network management, tailoring the use-of-system charge schedule to encourage smart charging may require regulatory pressure.

ii. Customer Billing

The tariff proposed here involves separate billing of smart and passive demand, which is currently not permitted by Ofgem[51]. Ofgem's customer tariff regulations are predicated on the Simpler, Clearer, Fairer reforms[52], since amended following recommendations from the Competition and Markets Authority (CMA)[53], which proposed that permitted tariffs are subject to the requirement that customers can compare competing alternatives simply:

> *ensure that customers (including those in vulnerable situations) are able to compare tariffs, are not misled and are able to make properly informed decisions.*

As the tariff proposed in this report allows homeowners to simply forecast their costs, it respects this principle and appears to comply with the spirit of regulation despite not being currently allowed.

iii. Suppliers' Ability to Guarantee Participating Demand

Consumers' rights to switch energy provider at 28 days' notice may limit the ability of suppliers to offer long-term PPAs to generators on constrained networks.

Suppliers may offer fixed-term tariffs that include significant termination penalties[54], which could mitigate the risk of losing smart demand to competitors, though in so doing they rule out dynamic pricing, and may deter more some customers, most obviously short period tenants. Given that this arrangement creates value for all participants, and respects the Ofgem requirements stipulated above, derogation of current regulations is not necessary to permit this solution.

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[51] Project partner V Charge have applied to Ofgem for a derogation to permit this arrangement for one of their storage heater tariffs.

[52] Simpler, Clearer, Fairer market reforms

[53] Modification of electricity and gas supply licences to remove certain RMR Simpler Tariff Choices rules

[54] SLC 22C

7. Conclusions

a. *Success and progress*

The ACCESS project has clearly demonstrated that in a real-life situation, a simple, community-owned Active Network Management (ANM) scheme can enable increased distributed generation (DG) on the network and improve the efficiency of network use by controlling dispatchable loads in hundreds of domestic properties.

Power flows on the network were kept within the prescribed limits and overall management and security of the network improved. Fail-safe measures embedded within the AMN controller ensured that even if the communication links were to drop out, the ACCESS ANM system remains well-behaved and does not cause problems for the network, the generator or the consumer loads.

The benefits accrue to all parties in various ways. The generator benefits by increased output with respect to a constrained situation; the householders benefit from increased use of local, low-carbon generation, controllable levels of comfort and possibly reduced energy consumption due to heaters charging at times closer to discharge times (thereby reducing heat-leakage losses) and the financial benefits thereof; the network benefits from reduced peaks and troughs in power flow leading to reduced thermal losses; the DNO benefits from a better-controlled part of the network and possibly better sight of power flows therein. There are also environmental benefits with less power wasted and increased renewable energy generation supported. This is truly a win-win mechanism that can be deployed widely to great effect.

Sight of critical network pinch-points is crucial to maximising the network benefits and close collaboration between the partners ensures that any issues that arise are promptly and thoroughly dealt with. Mutual respect and recognition of commercial sensitivities ensure that data is shared in a safe and appropriate way to achieve the best outcomes for all stakeholders.

The Introduction and Project Summary details the background, problem and solution along with the approach to testing that solution and analysing the results. The technical aspects have been proven and the usefulness of this approach clearly demonstrated.

b. *Thorough testing ensures robustness*

The carefully designed sequence of tests verified that the controller behaved as expected and all adverse situations were safely managed. The various tests and their successful outcomes are detailed in Section 5, Results of the ACCESS Trials. A series of similar tests will likely be incorporated into the witness testing and commissioning process of future deployments of this solution.

c. *Commercial models*

As well as developing a workable technical solution, it is important to build a commercial model that rewards participants appropriately and incentivises behaviour that is beneficial for all parties. Four models are analysed in the Potential business models section (6.f) and the development of a Tariff Design**Error! Reference source not found.** is discussed in the following section.

It is clear that involving the supplier in the value chain incentivises them to sign-up additional flexibility customers although there are also investment risks for the suppliers, particularly if the flexibility markets become very active.

The first model is similar to the set-up in this project and is based on the generator contracting with an aggregator that receives real-time data from the DNO. It is compatible with current regulations but price optimisation is not possible and value may be destroyed.

The second model is the Distribution System Operator (DSO) model where the DNO take on greater responsibility for balancing power flows on the distribution network. A responsibility to maximise renewable electricity generation incentivises them to procure load-matching as a flexibility service. Part of the generator's income would pay for the load-matching service provided by the DSO. Whereas this improves network utilisation, it does not reflect wholesale electricity prices nor provide a simple route for offering flexibility services to other requesters.

The third model uses a Licence-exempt supply arrangement to aggregate generation and load behind a single [virtual] meter point (MPAN/BMU). This market-based mechanism allows price discovery to benefit consumers and the generator. This concept is untested in GB and may not outperform traditional supply arrangements.

The final model is where a supplier offers a special tariff for flexible loads, contracting with an aggregator to manage these loads. This can efficiently reflect the local cost of electricity and the value of service provision. This may provide a good mechanism for the emerging domestic flexibility market but it is not particularly targeted at increasing renewable electricity generation at constrained sites and may fail to achieve the larger benefits desired.

Smart or advanced meters are likely to be at the heart of successful implementations of any commercial arrangement as half-hourly settlement is necessary to unlock the main value streams. Higher-frequency measurements and communications will be needed to enable the feedback loops or the control system. The more standardised these components are, the more financially viable the scheme.

d. *Learning Points*

As with all research and development projects, ACCESS faced a number of challenges to overcome and hence useful learning points, which are summarised below:

1. Participant relations

It is typically argued that customers don't need to know the detail of their energy supply system but experience with ACCESS is that **clear, background detail is required to build participant confidence.**

Providing **'just the right amount' of information for the project participants** has proved to be a challenge. Initial installations had various 'status' lights to indicate what the equipment was doing but this caused confusion and concern in some cases. As a result these status lights are best not used in this way.

When working within the tight time constraint of the programme for participant home visits, **multiple home visits were often required** for installing the various technology devices. Ideally, participant home visits should be minimised but many technological, telecom connectivity, weather and logistical challenges combined to prevent this.

In an innovation project, some things will always go wrong. It is important to get these **issues sorted quickly to protect local community groups' reputation**.

With multiple customer-facing points within the project, it's important to maintain a **central coordinator for participant engagement**. This has worked well in the project but it is easy for participants to get confused when there are many organisations involved. Given the local nature of the project, participant's preference will often be to speak to a local representative on the ground rather than calling the central customer helpline.

2. Economic Incentives

The current **peak / off-peak tariff structure complicates the economics of local balancing** for curtailment relief, and constitutes a significant barrier to the roll out of this approach.

A facilitating **local tariff proposition** could work in a very similar way to current Radio Tele-Switch (RTS) tariffs, with the supplier being able to buy lower cost electricity for participants, without a direct relationship between the participants and the generators.

The aggregated real time control of electric heating loads could also enable significant additional revenues to be realised by **providing energy services to operators**.

A community energy proposition of this sort would **widen the scope for community energy project**s, providing incentives to community energy groups **to participate in both additional generation deployment and facilitation of controllable demand**.

3. Installation and Maintenance

There are **inherent risks in asking installers to install a new sort of device,** or otherwise conduct an installation differently to their normal approach.

In order to mitigate installation risks, it the required **installation process must be simple** — VCharge has made a number of modifications to its InstallerApp over the course of the project to simplify the installation process.

Surveys and sign-ups must be completed in sufficient time to give ample lead time for supply of materials, kit and installation and allow for statutory ‘cooling off’ period.

When undertaking an innovation project of this sort, it is imperative to expect and mitigate against **significant unforeseen delays:** the most notable having been in the CE-mark testing of the dynamo units and in the software development required to *automatically* match the heating assets with the Garmony Hydro Scheme’s output.

Reliable internet connections are critical and **cannot be assumed,** especially in rural areas.

Local technical capabilities may take time to build up. However, **locally based expertise will become essential** in responding rapidly to installation and maintenance issues, and avoiding high ongoing running costs.

4. Control Strategies for Curtailment Mitigation

The ACCESS approach may contribute to mitigating key challenges in future network operability, as matching demand in real time against distributed renewable generation can not only **relieve constraint, but also reduce imbalances** and power flows on the wider grid:

The ACCESS approach of harnessing new controllable heating loads for curtailment relief is also very **well suited to support wind generators** in transmission-constrained areas of the distribution network, as demonstrated by the Heat Smart Orkney Project.

The **total controllable load should be at least as large as the maximum curtailment** and preferably double to allow for availability factors.

Residents use their heaters differently — the project found a wide variety of behaviour patterns in relation to storage heater usage in terms of frequency of use, how they controlled, and what thermostatic settings meant in reality to participants. This can be a teaching opportunity but ultimately the project must fit with the clients' behaviours, rather than expect clients to immediately change their behaviour. Most importantly, the project must ensure that **any changes initiated would not result in unforeseen or expensive consequences for participants who continue to use unorthodox control methods** under the new system.

The remotely-controlled **inter-trip network solution is technically suitable for purpose** and might therefore be used for new, otherwise constrained, generators

5. Project co-ordination

It is important to make sure there is **continuity of staff in each partnership** and, ideally, single-point of contact to keep teams up-to-date and suitably trained.

Large organisations in particular will have big teams and different departments who may need to be involved, updated, or consulted in a timely manner for sign off. It is important to speak with someone at a suitable level to coordinate this type of activity from the outset – and **keep in mind the varying timescales for sign-off of documents** especially in legal departments.

Don't underestimate **time/resource needed to 'join the dots' across various partners** when troubleshooting problems.

CES's ability as **project co-ordinator to act as a mediator**, and impartially resolve issues and negotiate task distribution between partners has been very important.

Protecting participant data flows with multiple stakeholder involvement is crucial particularly where project partners are local residents themselves. SSE Retail has standard processes for managing customer data to ensure correct protection mechanisms are implemented and no data breaches were reported across the whole of the project.

Appendices

A. The Partners

There are 5 partners in the ACCESS Project, each with distinct roles:

a. ***Community Energy Scotland***

Community Energy Scotland has led a consortium of five partners and a number of other project stakeholder organisations to delivering the ACCESS Project. Initially identifying and recruiting appropriate organisations to help achieve the project's goals. Community Energy Scotland is a Registered Scottish Charity which supports communities to develop sustainable energy projects. It is particularly focused on driving technical, policy and regulatory innovation to overcome barriers to community energy projects and enable the development of local energy economies. CES has a deep involvement in The ACCESS Project. As well as instigator of the project, it acts as lead partner & project manager, financial controller, project convenor and coordinator. In addition to these roles, CES has also been involved in the design of the communication system at the heart of The ACCESS Project. As the lead partner, Community Energy Scotland is the recipient of all LECF grant funding from the Scottish Government, which is drawn down as restricted funding according to an agreed drawdown schedule.

b. ***VCharge UK Ltd***

VCharge UK Ltd is a wholly-owned subsidiary of the US-based VCharge Inc. It builds hardware and software to coordinate 'Transactive Load'—that is, distributed electric load with embedded storage capable of responding intelligently to changing grid conditions. At present VCharge is the largest provider of residential demand side management in the US and has expert experience of the grid-related capabilities of night storage heaters. Its role in the project is to successfully deploy its VNET software platform for managing communications between the Garmony Hydro generator and storage heaters and install the recently launched VCharge Dynamo control hardware in all the heaters.

c. ***Element Energy ltd***

Element Energy ltd is a strategic energy consultancy specialising in the analysis of low carbon energy in transport, power generation and buildings. Its role in the project is the analysis of the Trial results and assessing the national potential for ACCESS solutions, based on detailed bottom up modelling for other types of generators and consumer archetypes, informed by the real world data from the Trial. It is also responsible for the analysis of potential commercial models for the ACCESS solution, identifying the key advantages, barriers and potential additional benefits and revenues.

d. ***SSE***

i. SSE Energy Solutions Ltd

SSE Energy Solutions Ltd is a wholly owned subsidiary of SSE plc, a vertically integrated energy utility and the largest provider of renewable energy across the UK and Ireland. Its role in the project is to oversee the installation of new heating in local homes, community halls and small businesses by the installation contractor, McGills. An SSE ES project coordinator is located on Mull 4 days per week to confirm installed units, oversee work in progress and ensure all installation and safety requirements are met.

ii. SSE Energy Supply Ltd

SSE Energy Supply Ltd is a wholly owned subsidiary of SSE plc. Its role in the project is to facilitate front-line ACCESS participant customer care and engagement and signpost to relevant partners as required. It contributed to defining the participant engagement strategy for the project and feeds back to the consortium partners to ensure the smooth delivery of domestic installations with SSE Energy

Solutions. They also calculate rebates for Total Heat-Total Control customers and others who have suffered technical glitches.

iii. SSE Power Networks (SSEN)

Scottish and Southern Energy Networks (SSEN) is not a formal partner to the ACCESS project but acts as project advisor and project funder. SSEN is part of the SSE Group and is responsible for the power distribution network in the north of Scotland. Its role in the project is to advise on the requirements for the safe and efficient operation of the distribution network in which the ACCESS project sits. The share of the project's costs which is met from OFGEM's Network Innovation Allowance is contributed via SSEN according to the terms of an approved NIA funding application. SSEN assisted in the design of the inter-trip signalling. They work with Element Energy to evaluate how this ACCESS solution can be implemented in other locations, developing the technical requirements and business models necessary.

e. ***Mull and Iona Community Trust (MICT)***

This community trust is a Registered Scottish Charity focused on improving the quality of life for the residents of Mull and Iona. It has two main roles in the ACCESS project: To facilitate the use of Garmony Hydro, via Green Energy Mull*, as a test bed for the technology being developed by the ACCESS project; and to engage with the local community to assist in the recruitment of properties to provide controllable demand.

B. Heating Demand Data Processing

Storage heaters participating in the scheme were monitored using:

- a charge meter, which reported total power used to charge the heater each hour
- a brick temperature probe, which reported the instantaneous temperature each hour.

From these, we created an hourly heat-stored dataseries (using Glen Dimplex data on heater charging) and a heat-out dataseries (given by the difference in heat added to store from heat-in). The average diurnal heat demand profile is shown below, alongside the heat demand profile from the Carbon Trust micro-CHP field trials.

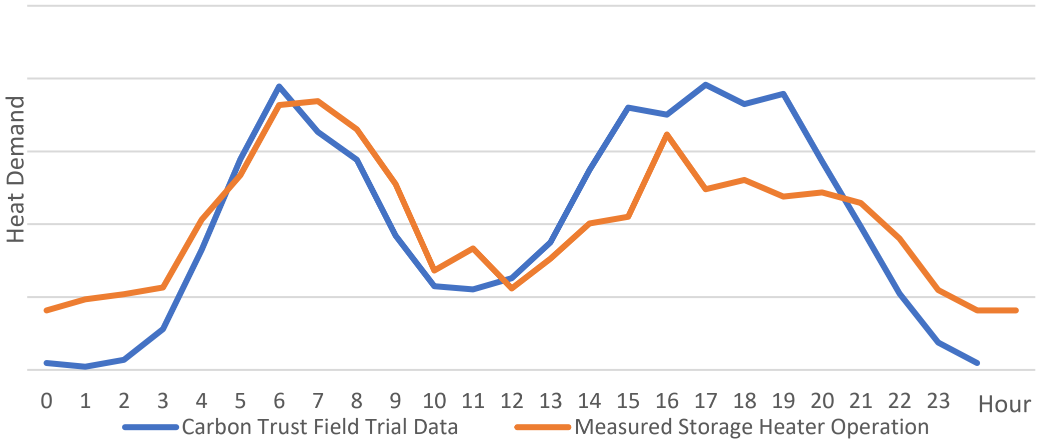

Figure 36 ACCESS heat demand vs Carbon Trust data

The representative, measured ACCESS heat demand shows good agreement with the Carbon Trust mCHP Field Trial data (Figure 36) although storage heaters appear to heat the home more in the early morning; this may be an artefact of the monitoring, with the brick temperature probe not fully recording the change in the internal temperature of the brick.

In some cases, gaps in the data have had to be filled; heaters reporting no data have had some gaps filled, while others – corresponding eg, to times at which the heaters have been turned off in summer, have not been altered. The agreement between heating degree days (HDDs) at Tiree and total estimated daily charging is shown below.

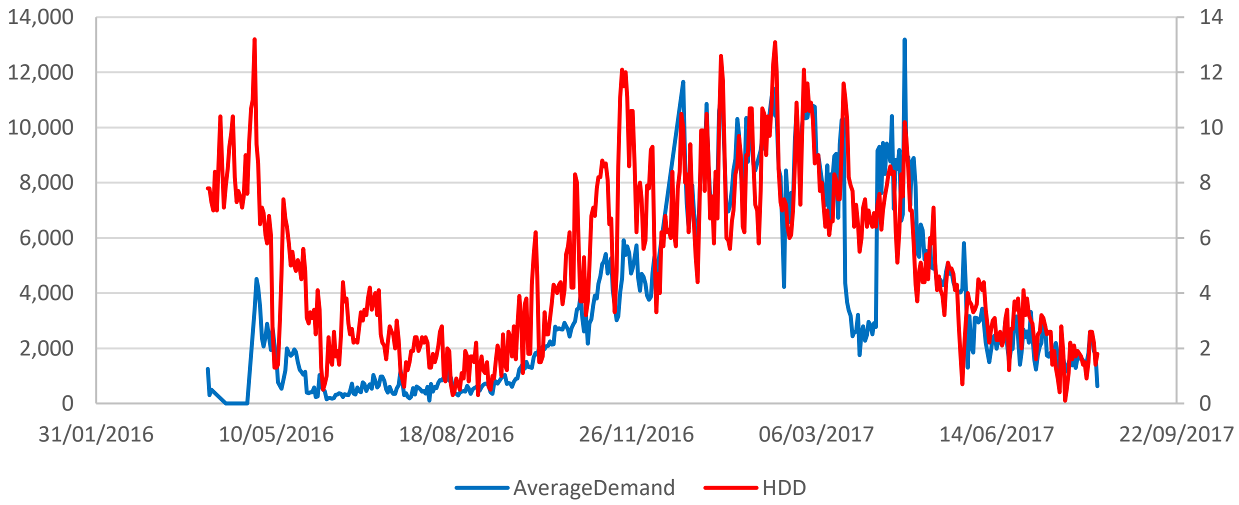

Figure 37 Average charging in watt hours (left axis) vs degree-days at Tiree (right axis)

The average charge per day correlates well with the heating demand as measured by the heating degree-day (HDD) measurement. The 15.5°C HDD data for Tiree is plotted in red on secondary/right-hand axis; the heater charge (in Watt-hours) is plotted in blue against the primary/left-hand axis. Scheme demand and heating demand agree well after summer 2016; data before this point has been excluded as that lack of correlation confirms suspicions about data veracity.

We note that some tariff peak and off-peak data is defined on a 15 or 30-minute basis, in these cases we have assumed charging takes place in the off-peak sections for profile creation, and in the peak section for rebate calculation.

The data also included a room temperature dataset, but it has not been possible to use this due to low resolution of the dataset and lack of data about the building fabric.

Due to the roughly triangular Garmony duration curve, curtailment increases with the square of the limit imposed on the export connection.

C. Creation of Reference Years

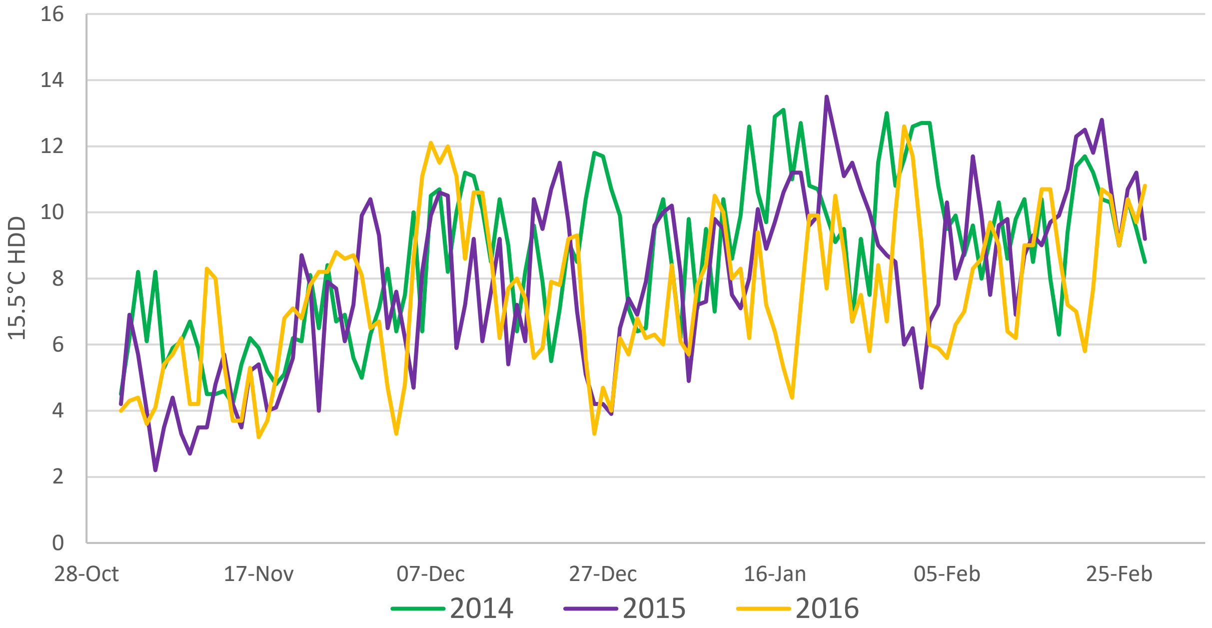

Figure 38 Daily Variation in Winter Heating Demand

The daily variation in heating demand (Winter 2014, 2015 and 2016) (Figure 38) shows that seasonal total demand varies marginally (by only around 10%), but weekly demand can vary by a factor of more than 2.

We use HDD data for Tiree (from Weather Underground) to create a "long term reference" daily annual heat demand against which the recorded data is compared, using the BRE methodology[55]. As 2015 and 2016 were relatively mild winters, the long term reference heat demand for Mull is 18% higher than the recorded values.

As the Garmony over one year's Garmony generation data, we can create an "average" annual output profile, though this is not referenced to a longer term dataset.

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[55] https://data.gov.uk/sites/default/files/10percent_analysis_methodology_v5_10.pdf

D. Garmony data

Generation data from the 400kW Garmony hydro plant for the Mull and Iona Community Trust[56]. This data is available at 15-minute resolution from 1st June 2015 to January 2018. There is a gap between 01:30 on the 7th and 15:15 on the 31st January 2018. For our analysis, we have produced an hourly annual average generation profile for a single year.

a. Garmony Curtailment as a Function of Export Limit

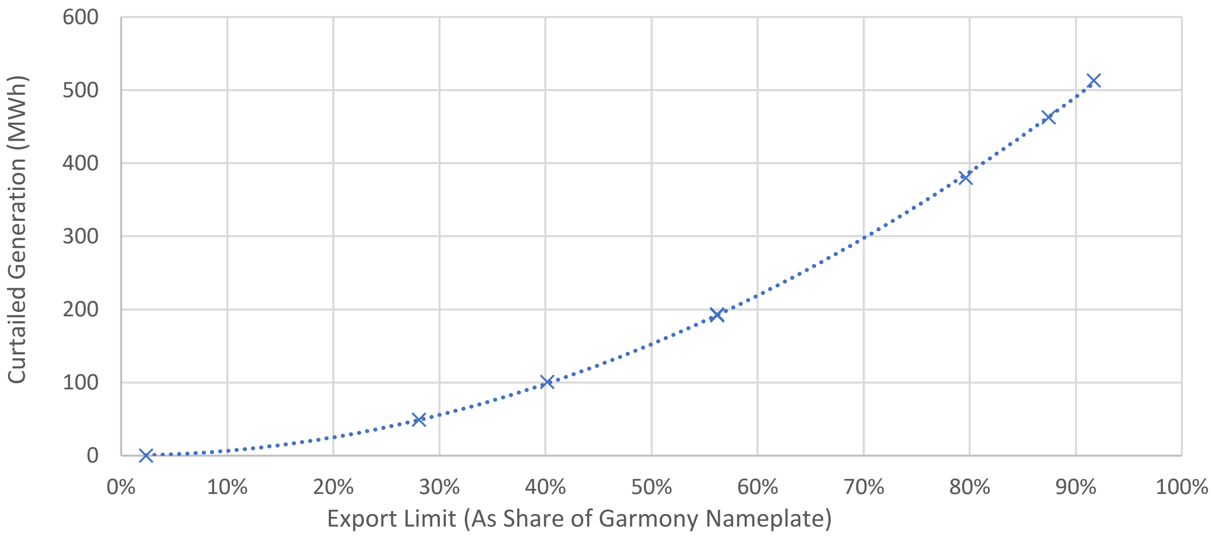

Figure 39 Curtailment vs Export Restriction

Plotting curtailment against the restriction on export (as % of peak Garmony) produce the graph in Figure 39. Curtailment is calculated against baseline generation and the fitted curve is a square trend line.

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[56] http://www.hydro-alerts.com/garmony

E. The Balancing Mechanism

Parties who buy and sell power (generators and suppliers) submit the amount the amounts of power they are bilaterally contracted to provide or consume for each half hourly settlement period to the transmission system operator (ESO) through Physical Notifications. By 1 hour before the start of each period, parties must have submitted their final position, known as their Final Physical Notification (FPN).

At gate closure, BM participants can also submit (up to 10) offers and bids before gate closure, indicating respectively, how much they would have to be paid to turn up, or would like to pay to turn down (the latter can be negative, ie, can involve being paid to turn demand down). Consumers can also submit offers (to turn consumption down) or bids (turn consumption up).

Each offer/bid is also associated with a (lower) bid/offer "undo" price, so a bid can be accepted and then "unaccepted" at non-zero cost by the ESO.

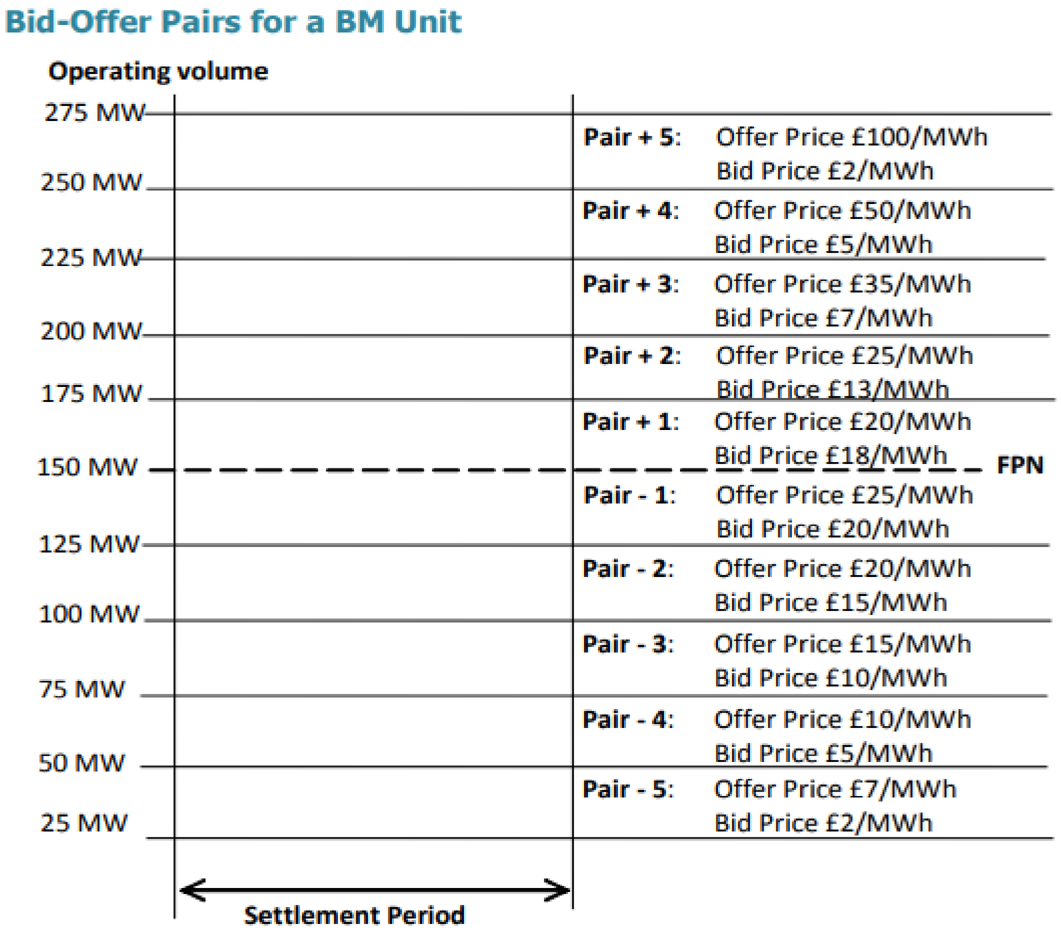

Figure 40 Balancing Mechanism market depth

After gate closure, participants cannot change their FPN (without having an offer or bid accepted).

The ESO then ensures there is the same amount of generation as (predicted) demand for the half hourly (HH) settlement period. If not, it has one hour to accept offers/bids from parties to turn generation up/down (or load down/up) through the Balancing Market (BM).

The ESO procures response by accepting bids or offers. Acceptance of an offer or bid is associated with a set of ESO instructions on how to deliver the deviation from the FPNs, defined by particular "spots".

For each accepted bid, the ESO contacts the BM Participant directly and instructs it to deviate from its FPN via a set of 'spot points'. Each spot point represents the change in output away from FPN at a particular time.

For example, below:

- Spot point 1 = 00:00, 100MW
- Spot point 2 = 00:05, 195MW
- Spot point 3 = 00:25, 195MW
- Spot point 4 = 00:30, 100MW

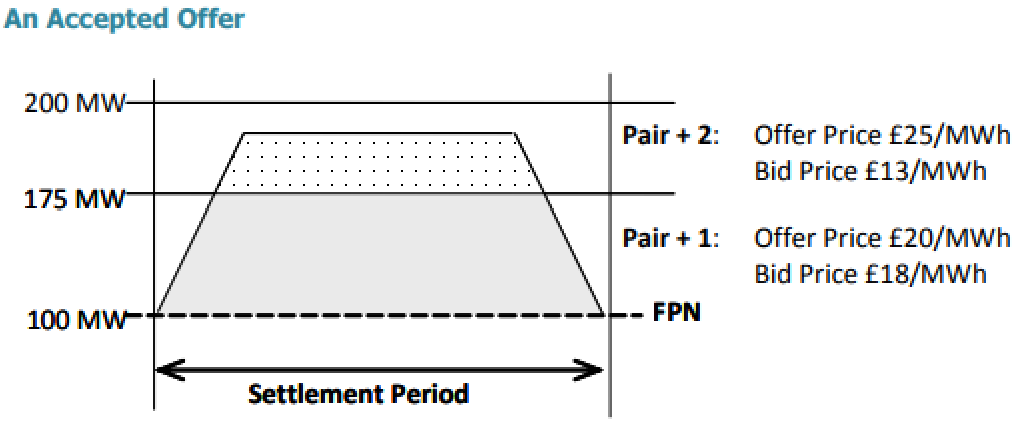

Figure 41 ESO Bid Acceptance defined by Spot Points

The highest per MWh accepted offer or lowest accepted bid price for a settlement period then determines the balancing price[57], referred to as the system buy price or the system sell price respectively. The BM is a marginal price auction; all providers of response pay or are paid at this price per MWh, not their bid price. Note therefore that in the above figure, **all** power generated (area under the curve) is reimbursed at (at least) £25/MWh.

It is also used as the balancing price; when metered consumption or generation data is collated (several months later), each parties' deviation from their FPN (their imbalance) is billed (or reimbursed, if extra power has been delivered or less used) at the SSP/SBP.

We note that prior to late 2015, each HH period was associated with a distinct SBP and SSP, leading to over-suppliers being repaid less than over-consumers were charged. Since then, there is a single system balancing price for each settlement period, rather than distinct buy and sell prices. A party whose imbalance is independent of market position is therefore value neutral. Table 26 shows the average spot and balancing price, the System Buy Price or SBP (balancing price when market is short) and the System Sell Price or SSP (balancing price when market is long).

Table 26 2016 Average spot and balancing price, SBP and SSP

	Cost (£/MWh)	Time Share
Spot Price	£38.7	
Balancing Price	£40.0	
SBP	£69.8	30%
SSP	£27.5	70%

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[57] Subject to some prices not being considered, and margins added by the ESO to account for STOR provision and other considerations.

F. Settlement

Even in a balanced market, individual parties can use or deliver more or less power than their FPN. This difference is also bought or sold at the system buy/sell price; accounting takes place several months later, after meter data can be collected and analysed.

For domestic and other non-half hourly metered customers, their consumption is estimated using the 8 Elexon profiles. These profiles specify for a given connection type, for each:

- day (Saturday, Sunday, Weekday)
- season (Winter, Spring, Summer, High Summer and Autumn) and
- settlement period (half hour)

what share of meter recorded generation is expected to fall in that period.

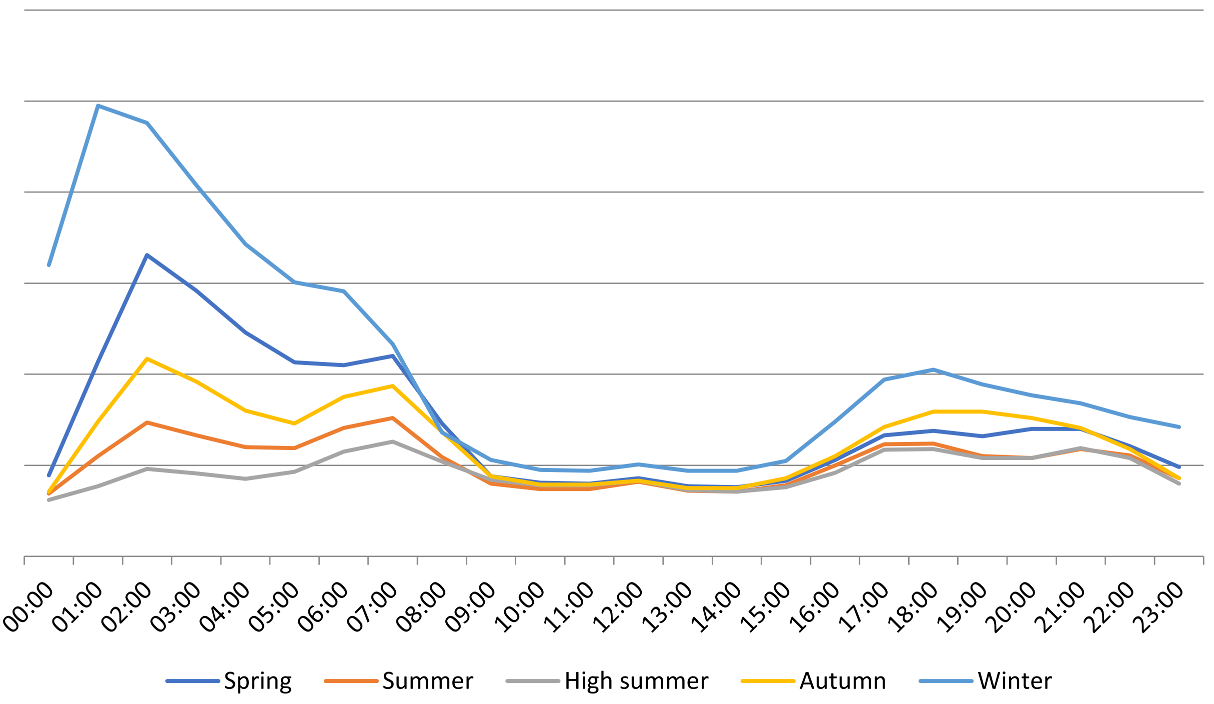

Figure 42 Seasonal Elexon Class 2 Profiles for weekdays

Representative Elexon Class 2 Profiles for a Weekday. Overnight heater charging can be seen reducing across the year. We note that all two-rate tariff tariffs are settled under the Class 2 (Economy 7) profile, and that the low and standard rate meter readings are not considered separately for settlement.

The 8 profiles classes are

1. Domestic Unrestricted Customers
2. Domestic Economy 7 Customers
3. Non-Domestic Unrestricted Customers
4. Non-Domestic Economy 7 Customers
5. Non-Domestic Maximum Demand Customers with a Peak Load Factor of less than 20%
6. Non-Domestic Maximum Demand Customers with a Peak Load Factor between 20% and 30%
7. Non-Domestic Maximum Demand Customers with a Peak Load Factor between 30% and 40%
8. Non-Domestic Maximum Demand Customers with a Peak Load Factor over 40%

G. Frequency Response

a. *Operating Principles*

In addition to the half hourly energy balancing described above, the ESO also matches power levels on the grid on a second-to-second basis. The national electricity network is designed to operate at 50Hz, though the frequency varies with real time fluctuations in the system-level balance between demand and generation; if demand is greater than generation, the frequency falls – if generation is greater than demand the frequency rises. Following a system fault, such as a generator tripping a circuit breaker due to voltage mismatch with the grid, there may be a significant difference between generation and demand, and therefore the system frequency changes significantly. The ESO must ensure that:

- The maximum deviation of frequency after a normal loss is no greater than 0.5Hz.
- The maximum deviation of frequency after an infrequent loss is no greater than 0.8Hz.
- Any deviations outside 49.5Hz and 50.5Hz do not exceed 60 seconds.

b. *Dynamic and Static Frequency Response*

Responses for dynamic FR services are proportional in power as grid frequency moves away from 50Hz; static responses operate at fixed power after frequency moves outside a specified limit (typically, 49.7 and 50.3Hz). In order to control frequency pre-fault acceptably, a certain minimum amount of dynamic response is needed. The remainder of the response requirement can be met with either static or dynamic response. The minimum amount of dynamic response that is acceptable varies with time of day and is higher overnight. The effect of this requirement for a minimum amount of dynamic response can be seen when the requirement is low, ie, during weekdays during the winter. Enhanced response is a dynamic only service; primary, secondary, and high response can be provided as dynamic or static services[58].

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[58] National Grid – Firm Frequency Response

H. Opportunities for Service Provision

Storage heaters have a primary use case; keeping homes warm. Above we find they may be managed to simultaneously increase local network ability to absorb and connect renewable generation. They may additionally interact with the wider grid, generating user value by moving consumption to periods of low supply cost, or providing services to the Electricity System Operator (ESO); helping to balance supply and demand.

Table 27 Parties in the Energy System

Party	Role
Supplier	Sells power to the consumer
Generator	Generates power, which is then bought by the supplier
DNO	Operates the distribution network (DN); has a legal obligation to manage the electricity infrastructure and keep voltages within statutory limits. The UK is split into 14 Zones, covered by 6 DNOs
ESO	National Grid, operates transmission network; Balancing Mechanism, Ancillary services, Capacity Market

Domestic customers interact only with their supplier and are charged according to tariffs that cover their energy consumption and use of system (UoS); in this section, we explore the extent to which these costs can be mitigated. The composition of a typical domestic electricity bill is shown below.

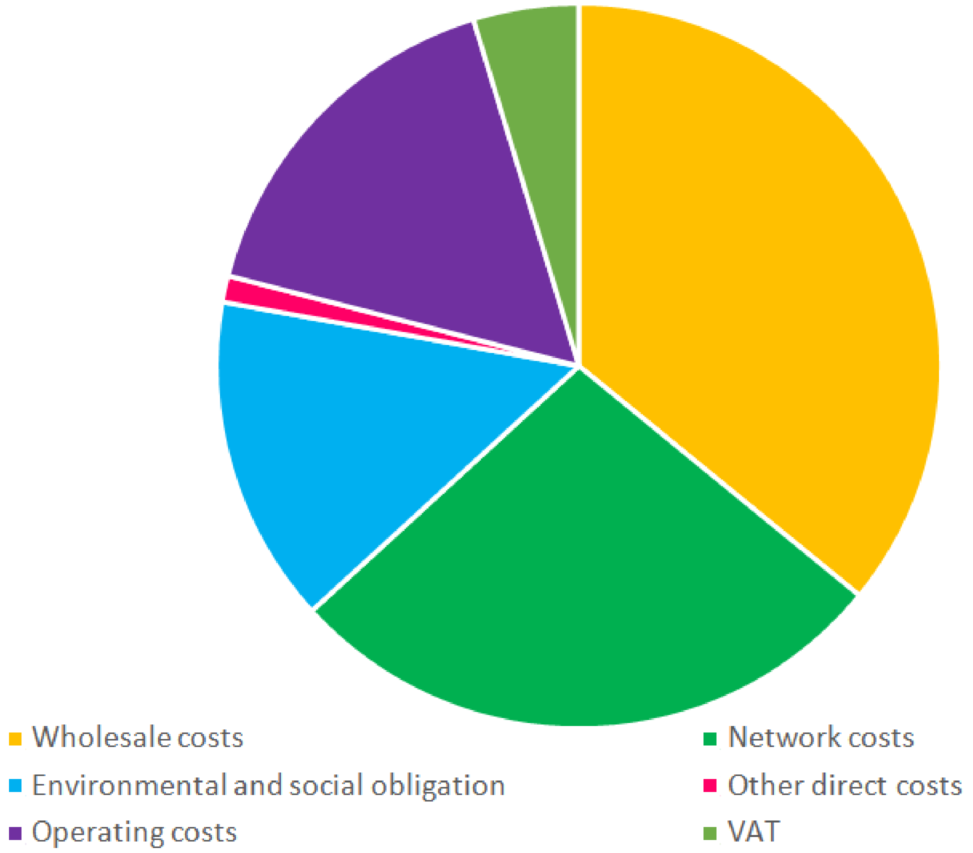

Figure 43 Ofgem Breakdown of Electricity Costs[59]

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[59] Breakdown of an electricity bill

Throughout this analysis, we report savings as a share of the long-term reference heating bill from the ACCESS trial—£750. In homes heated where no additional heating fuels are used, bills are likely to be higher. Wholesale electricity costs represent the largest single component of a consumer bill and we investigate the potential for DSR to reduce these costs in the following section.

i. Domestic Wholesale Cost Optimisation

Generators sell power to suppliers (they may not sell directly to consumers). Prices are determined at any one time by the marginal cost of the most expensive plant required to generate sufficient power to match the demand and so the price varies with demand levels. As such, prices tend to spike at around 10:00 am and again in the evening, around 6:00 pm. Market Index Data (MID) prices are published by Elexon, giving the volume weighted average power price for each of the 48 half hourly settlement periods each day.[60]

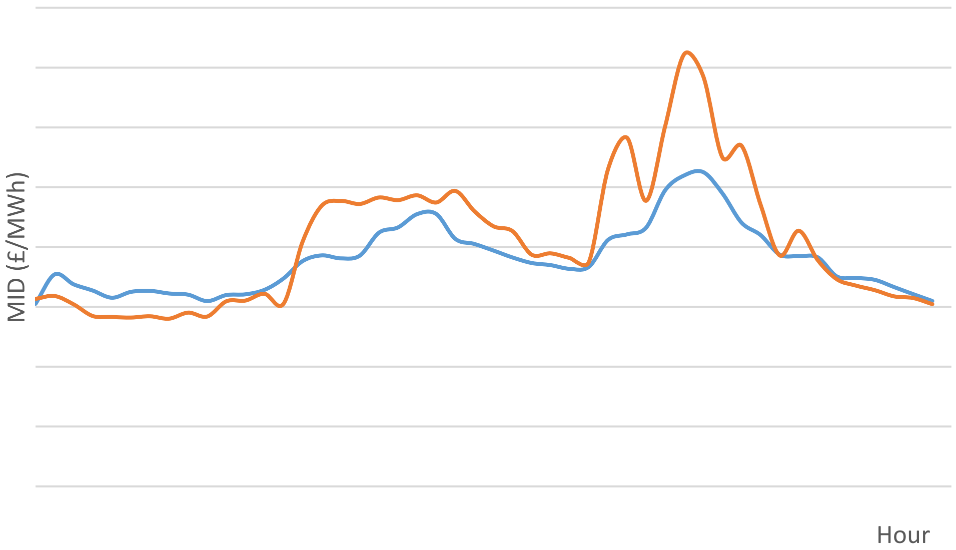

Figure 44 MID Price for 6th and 20th January 2016

Suppliers must reconcile the amount of power they buy and the amount their customers use, this process is called 'settlement'. Historically, customers' roughly quarterly meter readings have been used to settle their suppliers' position in each half hourly settlement period using the Elexon Class 1 (flat-rate) and Class 2 (two-rate) profiles; two representative electricity demand profiles (explained in appendix F). Since July 2017 however, suppliers have been able to settle their domestic customers' demand half hourly[61]. This requires a meter capable of recording demand on a half hourly basis; in practice this is likely to be smart meter, which all homes are due to have installed by the end of 2021.

Suppliers may in turn bill their customers on a half hourly basis including a margin that covers their use of system (UoS) charges and other price components and are, in principle, free to use non-meter data (eg, consumption reported by smart devices) in calculating customer bills. Flexible, half hourly, settled domestic demand can then optimise over this price variation; charging only during the lowest daily price settlement periods.

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[60] We use spot—rather than future—market data. We do not consider the effects and opportunities of future market participation in this analysis; though participation in future market (eg, to hedge power prices) should not affect the provision of other services.

[61] Ofgem Consultation

Using 2016 spot price data, we estimate that charging using the optimal, daily rather than baseline profile lowers the wholesale component of the cost of heating for ACCESS participants from £36/MWh to £26/MWh. This corresponds to a total saving of £70/year—9% of the annual heating bill.

Demand flexibility also allows suppliers who can defer charging to exert downward pressure on prices in negotiations, particularly in the 70% of the year when the market is long (see section E). To quantify this, we replace the spot price with the mean of the spot and the system sell price[62] (where it is below the market average), reflecting a level that both suppliers and generators prefer to their alternatives (respectively: buy at market average and spill into the Balancing Mechanism). This results in an additional saving of £10 per household.

Table 28 Market Price Optimisation Value

	Average Wholesale Cost (£/MWh)
Un-optimized Bill	£36.35
Lowest Cost Spot Prices	£25.65
Buy power lower price in long market	£24.06

It is therefore possible to reduce a household heating bill by around £80 or 10% through daily charge optimisation. We note that price optimisation saving does not vary significantly with heater size or annual demand; therefore, a 10% saving is possible across storage heated homes, regardless of type (council flats, cottages).

ii. DUoS Charges

Distribution network operators structure their distribution use of system (DUoS) charges to reflect capacity and constraints in their network and to equitably recover their permitted investment, operating costs and residual charges (sunk costs).

Different users are charged for their system use according to different DNO tariffs; the SSEN charge schedules for domestic flat rate (Elexon Class 1 settled), domestic two-rate (Elexon Class 2 settled) and domestic half-hourly metered are shown below. Since domestic half hourly metered and two-rate DUoS charges are calculated differently, individual customers' use of system charges may increase under the former. As shown above, average network use charges comprise 28% of consumer bills, second only to generation costs. Therefore, a risk exists that value created through market price optimisation is undone by an increase in DUoS costs as customers move from non-half hourly (NHH) to half hourly (HH) charges.

Table 29 SSEN Domestic DUoS Schedules[63]

Tariff name	Unit charge 1 (NHH)or red/black charge (HH) (p/kWh)	Unit charge 2 (NHH) or amber/yellow charge (HH) (p/kWh)	Green charge(HH) [p/kWh]	Fixed charge p/MPAN/day
Domestic Two-Rate	2.464	0.267		3.04
LV Network Domestic HHM	9.419	2.005	1.227	4.55

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[62] The price paid to generators for oversupply. See appendix E and F.

[63] SSE DUoS Schedules

Table 30 SSEN Domestic DUoS Schedule Times

Time periods	Red Time Band	Amber Time Band	Green Time Band
Monday to Friday (Includes Bank Holidays)	16.30–19.30	08.00–16.30 19.30–22.30	00.00–08.00 22.30–00.00
Saturday and Sunday		16.00–20.00	00.00–16.00 20.00–00.00

The domestic DUoS Schedules for static two rate ToU tariff and Low Voltage (LV) Half-Hourly Metered connections may lead to different domestic use of system charges associated with heating.

Below, we show the DUoS charges associated with the price optimised profile modelled in the previous section and the Baseline and Forecast local load matching profiles created in the previous section for the Central Hydro scenario.

Table 31 Annual DUoS associated with Thermal Demand

Load Matching Profile	Non HHM DUoS (£/year)	HHM Baseline DUoS (£/year)
Baseline	£78	£124
Price Optimizing	£63	£80
Forecast Matching (Central)	£115	£140

The Annual DUoS that is associated with household heating increases under a move to half hourly settlement in all cases, (but may be offset by reductions in the charges associated with appliance demand).

We find:

- In all cases, consumer use of system costs associated with storage heater charging increase under a move from the Elexon class 2 DUoS tariff to the domestic HHM schedule. As most passive charging takes place in off-peak, it is associated with the very low 0.267p/kWh usage figure, while the minimum charge for HHM charging is 1.227p/kWh, around 5 times this value.
- The greatest UoS costs are associated with management of heater charging to mitigate local curtailment under half hourly metering, at £140/year. This is £60/year more than the UoS costs of passive charging for non-half-hourly metered homes, and represents 75% of the FiT value of the avoided curtailment.

  Current use of system charges then negates much of the value created through load matching, especially if higher resolution demand metering is required.

  Therefore, as well as supplier tariffs that encourage local demand matching, DNOs may need to create a schedule to incentivise smart storage heater operation. Otherwise, increases in use of system costs may undermine the business case for matching local demand and supply even for highly subsidised generators.
- As both power prices and DUoS rates increase with system demand, optimising wholesale energy costs is associated with a reduction in use of system costs, particularly under half hourly settlement. Moving from baseline passive charging (£78/year) to HHM price optimised operation (£80/year) is UoS value neutral, ie, the cost is much the same.

SSEN may need to revisit these as smart meter roll-out proceeds, especially if they take an interest in encouraging active management of domestic demand or encouraging half hourly metering. Furthermore, DNO charge schedules vary regionally so, while the wholesale analysis applies nationally, UoS conclusions do not.

iii. DSR Revenue Streams from the ESO

National Grid (NG) operate the UK energy network; maintaining grid frequency and reactive power levels within prescribed limits and matching generation and demand during each half hourly settlement period. They also ensure there is sufficient redundant generation connected to the network through the capacity market. NG procures these services:

1. through mandatory conditions on connection agreements,
2. through bilateral contracts,
3. through competitive (marginal price) auctions

Demand management of storage heaters can provide services to the grid; we consider both fast response, high value frequency balancing products and high volume, low value energy matching services. Figure 45 below shows shorter response times offer greater revenues to service providers

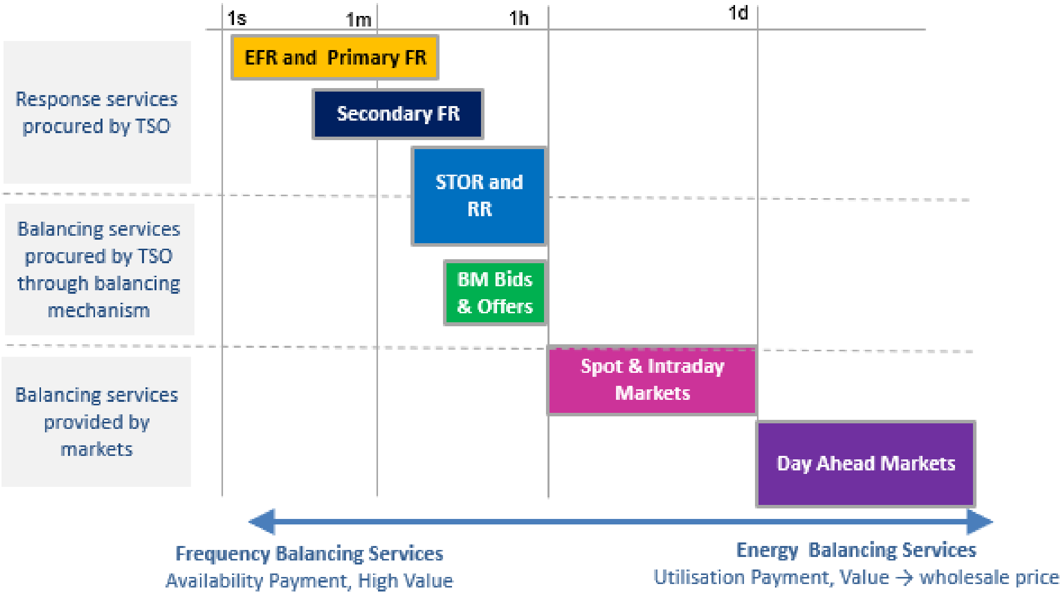

Figure 45 NG Grid Balancing Services Ancillary Services

The frequency of the power grid moves up and down in real time in response to the changing balance of supply and demand. NG are responsible for maintaining the frequency within 1% of 50Hz.[64]

To regulate the system frequency, NG procure a range of frequency regulation services, both "positive", which increase the system frequency by turning demand down or generation up and "negative" which decrease the system frequency by increasing demand or decreasing generation. These services are characterised by the response time—how quickly they must react to an observed deviation from the system frequency—and the duration time—how long the response must be maintained (Figure 46).

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[64] See appendix G.

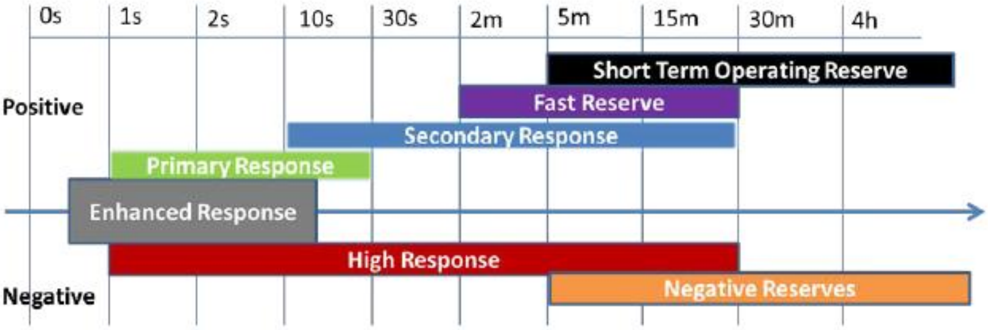

Figure 46   National Grid frequency regulation services products.

Reserve is the only service where both positive and negative responses are routinely called. A single asset can provide various services at different timescales[65].

Heaters only charge for around 1,000 hours each year and are thus better candidates for demand turn-up than turn-down service provision, ie, negative reserve. For the purposes of investigating replication of the ACCESS model the value of High Response (HFR[66]) and Demand Turn Up (DTU)[67] provision was investigated.

Storage heaters are technically ideal appliances to provide Frequency Response (FR[68]) but the times when heat is needed are generally not the same as the times when National Grid are looking for more demand on the system. This severely limits the amount of response that they can offer.

"Turn-up" provision by heaters (ie, increase in the power drawn) is limited by both power and energy considerations. Respectively:

- response power is limited by the minimum headroom at times of high frequency deviation; this is the dominant limiting factor in winter, when heaters are used at high utilisation factors[69], ie, when homeowners are most likely to have their heaters turned on to keep warm.
- Total energy throughput is limited by the heat that can be stored without making the home uncomfortably hot. This is the dominant factor in summer, when total thermal demands are low and the heat store is not depleted by it being used in the home so as to make space for more heat to be stored subsequently.

As the volumes of High FR are greatest in the summer, it is the second factor that limits annual provision. The constraints imposed on heater provision of ancillary service by user operation and thermal comfort requirements were not explored in the ACCESS Trial and therefore results are theoretical. Figure 47

---

[65] Future Requirements for Balancing Services

[66] High FR can in theory be offered as a dynamic or static service, but NG has no plans to procure static high response out to 2020.

[67] EFR must be offered as a symmetric service (responding to both positive and negative frequency deviations) and is therefore not considered although an aggregator could include storage heaters as part of a portfolio of flexible loads providing this service.

[68] Under a bilateral arrangement between ACCESS partner, VCharge, and National Grid, storage heaters are used to provide a bespoke Fast Dynamic Frequency Response (FDFR) product. This service leverages the electrical characteristics of storage heaters to partially decouple service response and demand volume. However, as the commercial details of the agreement are not public, no analysis of the associated revenues is included here.

[69] As peak daily stored heat values are constrained for local load matching, the charging approach does not affect capacity to provide these services and provision of FR and load matching do not interfere with one another.

below shows that the monthly demand of storage heaters is negatively correlated with daytime and overnight volumes of Dynamic High FR procured by National Grid[70].

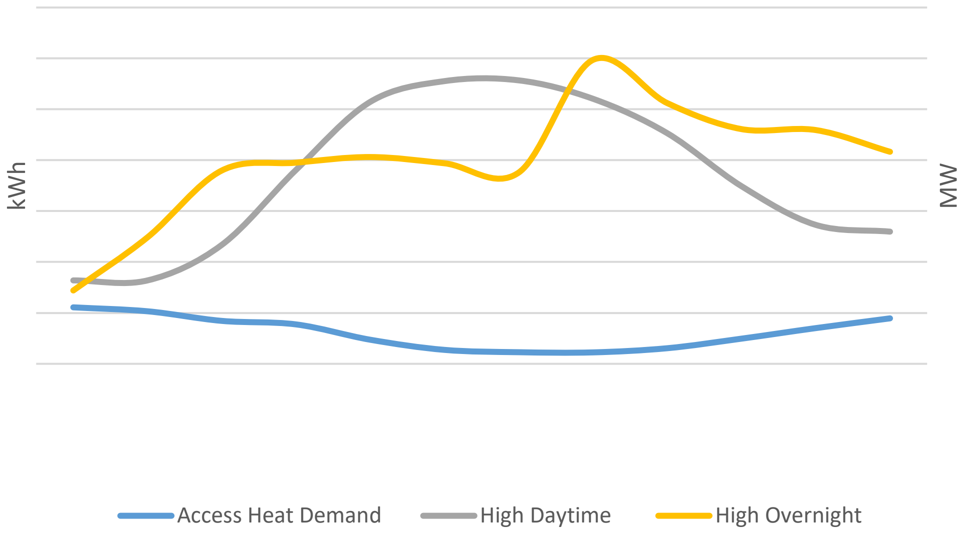

Figure 47 Monthly storage heater demand (kWh) vs Dynamic High FR (MW)

A dynamic utilisation profile was derived from NG grid frequency data[71] and it was found that through optimising portfolio charging, aggregators can offer 60% of their total heater capacity to provide High FR annually, corresponding to 5.5kW per home (1MW, corresponding to around 120 homes, is the minimum load size for service provision, so aggregation is required).

Firm Frequency Response (FFR) prices differ across monthly procurement rounds and required volumes vary seasonally and by settlement period. The volume-weighted holding price per MWh reported by NG for FR (both mandatory and commercial)—£13/MW/hour—was used as the expected availability payment. This value—the total cost of FR provision averaged across the MW procured—represents an upper bound on High FR value.

However, as EFR provides an increasing share of fast frequency response services, and grid scale batteries and distributed storage competing to offer ancillary services exert downward price pressure, the FR could fall to as low as half the (symmetric) EFR availability payment of £9.44/MW/hour[72]. Service provision at this price is therefore also considered.

Table 32 High FR Provision Value differs widely under current and likely future prices.

	Availability @ £5/MW/h	**Availability @ £13/MW/h**
Annual Value	£226	£587

---

[70] Data from NG FR data portal for 2016.

[71] NG Frequency Data. As per this document, a dead band of 0.015Hz is used.

[72] The symmetric service PCR is the only rapid frequency restoration service on the European Synchronous grid. If NG procured all regulation symmetrically, aggregators could then use storage heaters to in combination with complementary demand turn-down loads and/or only bid for provision during charging hours. NG's Future of Balancing Services road map does not indicate this as likely.

While EFR contracts are four years long, FFR procurement volumes vary by month and settlement period. It may therefore be possible to provide a greater share of individual heater capacity for High FR on a day- or week-ahead procurement basis, rather than through a fixed annual volume.

On the other hand, FR provision capacity may be reduced by increased heater use leading to lower headroom (due eg, to a particularly cold winter) or by lower thermal demand (due to eg, a warm summer).

It is noted that heaters would need to remain connected all year round to provide an annual service, for which the returns are presented. Some ACCESS participants appear to disconnect or turn off heating over the summer; this would decrease the aggregator service provision capacity.

A. Future Frequency Balancing Services

National Grid intend to introduce a rapid response, brief duration Frequency Containment product[73] by the second half of 2018. DSR storage heaters may be better technically and operationally suited to provision of this service than high FR, so the revenues available from this product may be greater than those modelled above.

National Grid propose introduction of a 60 second response time Frequency Containment product, the negative component of which could be provided by storage heaters with minimal effect on thermal operation. (Figure 48)

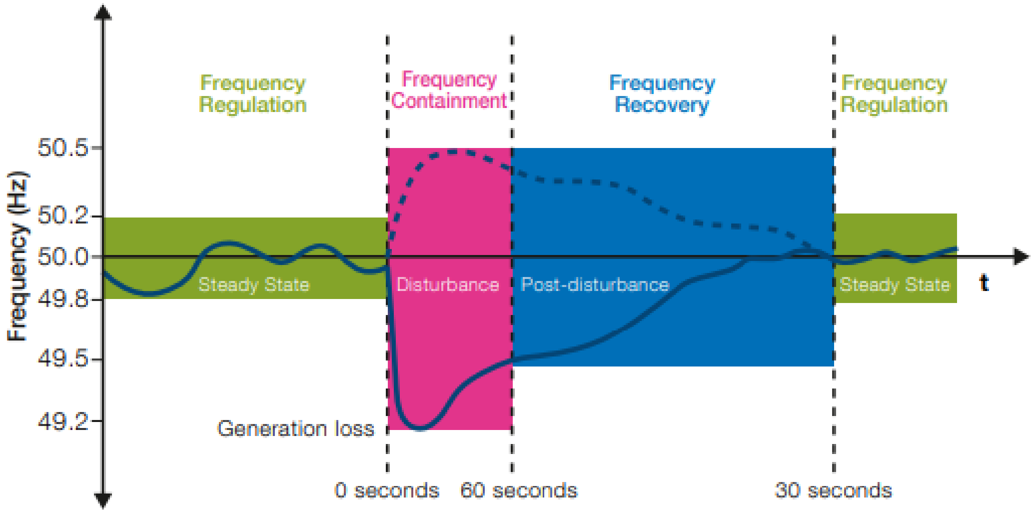

Figure 48 National Grid 60 second response time Frequency Containment proposal

B. Demand Turn Up

Demand Turn Up (DTU) is National Grid's foot-room reserve service, used to manage the grid at times of low demand and high supply. DTU guarantees the ESO generation matching response at a fixed price, avoiding the need to procure large volumes of turn-up on the BM (see following section). This service was created primarily to address system level over-supply from wind and solar PV during off-peak demand periods, as indicated by the provision windows.

---

[73] National Grid-Future of Balancing Services Roadmap

Table 33 Turn-Up Service-Required Availability

Months	Overnight	Daytime
May and September	23:30 to 08:30	13:00 to 16:00
June, July and August	23:30 to 09:00	13:00 to 16:00

Winning providers at the 2017 procurement round were awarded an availability price of £1.50/MW/hour, with utilisation payments of between £60/MWh and £100/MWh[74]; less than the retail cost of power.

Modelling suggests that as this is a volume-based service procured during summer, it matches poorly with storage heater operation; only a very small share of capacity can be bid and the revenues earned are negligible.

This suggests that, at the system level, the value of load that can be matched to renewable over-supply is less than the retail cost of that energy (roughly equal to an industrial tariff price) and the value of the service is around 10–20% of frequency regulation services.

iv. Balancing Mechanism

Suppliers and generators trade their demand on markets, from up to years ahead to one hour before the start of each half hour settlement period ("gate closure"). At this point, the Final Physical Notifications (FPNs) of each participant are fixed and the system operator calculates the difference in the total power sales contracted and the expected demand. The ESO does this by assessing the FPNs of the generators and suppliers and comparing that assessment to its own forecasts for the Settlement Period.[75]

The market is said to be long if too much electricity has been sold, or short if too little. The ESO's task is to address this imbalance at the lowest possible price, by buying generation or selling demand. The procedure is explained in appendix E.

Storage heaters can provide services to the BM; turning demand up when the system is long and down when the system is short. The BM operates through marginal price auction; all providers of response pay (or are paid) the balancing price for each MWh they provide, rather than their bid price[76].

Participation in the BM with perfect foresight is worth £67/household/year; 20% of this value comes from postponing charging when the market is long and 80% from turning up to absorb cheap power when the market is short.

It is noted that this analysis builds on, and is therefore consistent with, the price optimisation profile from the section above. Also, as volumes of less than 1MWh are considered *de minimis* and are ignored, an aggregator would need at least 2MW of demand—over 200 participating homes—to provide services to the BM.

v. Capacity Market

The Capacity Market (CM) aims to incentivise investment in the generation capacity required to maintain a margin between net system consumption and total available generation. Payment is via a marginal price auction-determined availability payment to plant that can turn generation up (or demand down) in response to an ESO control signal, typically four hours ahead of the delivery time. Both new and existing plant can participate in the CM.

---

[74] Demand turn up—Market Information

[75] Elexon—Guide to the Imbalance Mechanism

[76] This means that BM participants' optimal strategy is to report their true marginal cost of response, which for a storage heater at the start of a charging period may be close to zero.

Storage heaters may participate in the current, transitional CM through the DSR auction; the current clearing price for which is £45/kW/year[77]. Provision can be offered as a time-banded service, so that heaters could offer turn down response for the roughly 1,000 hours in the year for which they operate. However, it is not clear that there is equal demand for the service across the year and during typical heater charging windows in particular; the value of CM DSR response during these periods may be lower than the average. Also, the heater's primary use may reduce possible turn down, particularly during cold winters. Therefore, £40/household/year represents an upper bound on CM participation value.

Tendering "Unproven DSR" for CM participation is capital intensive, with NG requiring a "bid bond" which is held in escrow until the platform response is demonstrated. National Grid, however, aims to fully exploit the potential of demand side responders in the Capacity Market[78] and a streamlined tender process could simplify participation for domestic heating.

vi. Services to the DSO

DNOs are responsible for ensuring the integrity of the distribution networks. Historically, they have taken a largely passive role in network management but to enable a greener energy system, they are beginning to transition to Distribution System Operators (DSOs), who:

> *operate and develop an active distribution system comprising networks, demand, generation and other flexible distributed energy resources (DER). As a neutral facilitator of an open and accessible market it will enable competitive access to markets and the optimal use of DER on distribution networks to deliver security, sustainability and affordability in the support of whole system optimisation. A DSO enables customers to be both producers and consumers, enabling customer access to networks and markets, customer choice and great customer service.* [79]

Rather than offering firm-connection offers only, DSOs will:

> *Provide fair and cost-effective distribution network access that includes a range of connection options that meet customer requirements and system needs efficiently.*

Using real-time monitoring and control of network components will increase renewable capacity without expensive investment in traditional network reinforcement.

WPD, UKPN and (in Orkney) SSEN trials have started offering non-firm connections on constrained grids, under which embedded generators are turned down at times of insufficient capacity (or other network constraint). Connection to these actively managed network (ANM) zones is typically preferable to renewable generators to paying for the grid reinforcement needed for a firm connection.

The next generation of ANM zones may match local flexible demand to supply, avoiding or mitigating this curtailment. To procure these services, DSOs would contract with aggregators to control local load. Further ahead, DSOs may actively manage network parameters other than load and service provision to the DSOs and ESO may be jointly procured through a harmonised market place.

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[77] DSR Transitional Auction 2016

[78] ENGIE, Understanding the Capacity Market, p. 4;

[79] Opening Markets for Network Flexibility

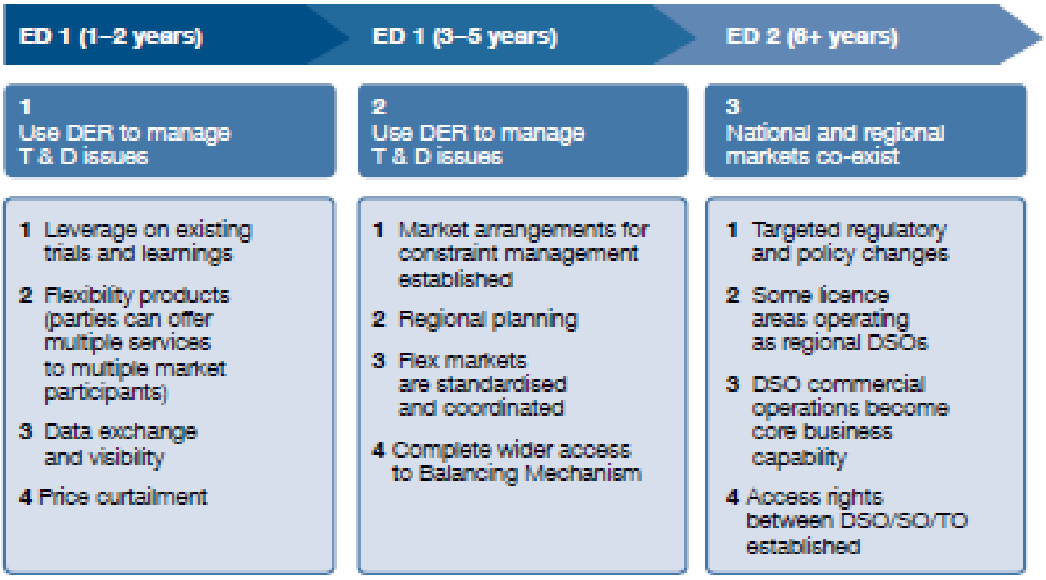

Figure 49 Open Networks Roadmap to Harmonised DSO/ESO Service Market

More immediately, as above, to unlock domestic DSR, DNOs may need to modify their use of system schedules, which currently disincentivise electrically heated homes both from moving to half hourly settlement and from moving heater demand from off-peak (in the case of DNOs green band) to peak (red or amber/yellow band) periods.

Revenue for DNO service provision is not modelled here since:

- While local markets are emerging[80], there are currently no DNO services available to the ACCESS scheme.
- In load matching ANM schemes, the total value available to the DNO for load matching procurement is given by the value of the curtailment mitigated, under an arrangement where constrained generators effectively may ask for this service. This value will clearly depend on the specifics of individual network branches and is the same value as considered in the previous section.

This arrangement has structural features, however, which are discussed in section 6.6.c.

vii. Costs of Delivery

Glen Dimplex, who supply the majority of the UK storage heater market, aim to have a controllable heater on the market by early 2019[81]. This will be sold at a price no higher than the current version; instead, the business plan is to utilise the propriety Glen Dimplex platform, to control the heaters and avail of their flexibility.

On this basis, the additional cost to the consumer of using a smart heater is zero and there is no barrier to replacement of the 18GW[82] of storage heaters with a similar amount of smart enabled plant by 2030.

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[80] There are local markets for ANM in parts of the country. UKPN for example procure both Outage Response Service (LV), in which stored capacity provides holdup power to customers in the event of outages, simulating the role a flexible generator; and MERFlex, in which a V2G assets provide a flexibility service to the distribution HV network and avoiding more costly planned works.

[81] The heater will be controlled by radio signal from a packaged home energy controller, which is linked over internet protocol to the Glen Dimplex Cloud.

[82] BEIS Domestic DSR Competition—Competition Guidance Notes

Aggregator/supplier margins may however be reduced through licensing fees, though currently the size and structure of license fees is unclear.

I. Test result reports

ACCESS Project Mull Live Following Testing 14/11/2017

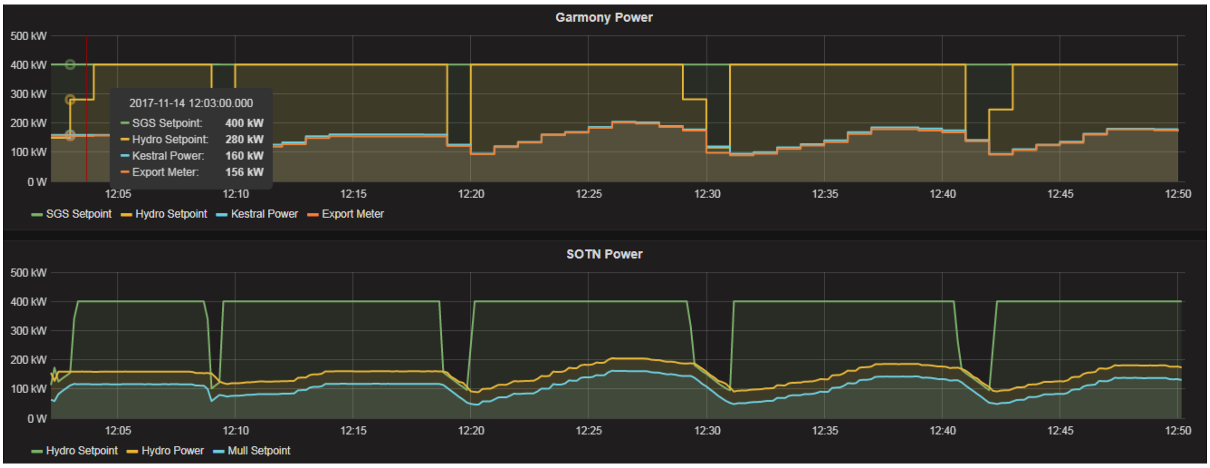
a. *Test 1—Following a Cranix signal with active curtailment—PASS*

i. Aim & Method

Ensure that the normal operating mode of the SOTN and VSCon are working. A simulated Cranix was used rather than heaters, so the demand could be controlled. Power demand was cycled from 50–160kW.

ii. Data

https://tsdb.veecharge.com:3000/dashboard/db/garmony?from=1510660931019&to=1510663819299



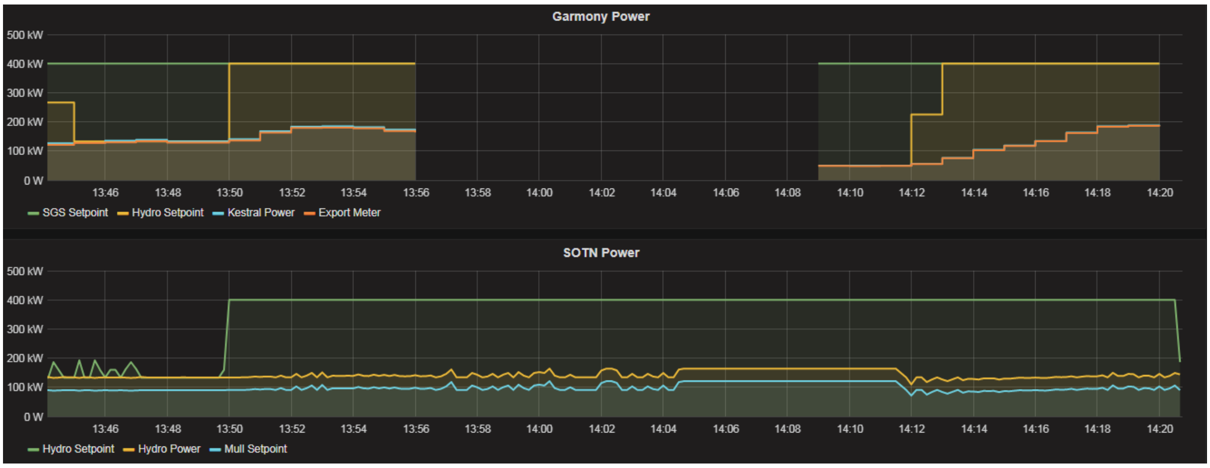
b. *Test 2—Communications failure between VSCon and SOTN—PASS*

i. Aim & Method

Ensure that the virtual constraint of 50kW would not be violated when the communication failed to the VSCon. Also ensure that normal operation resumes upon the comms being re-established. To instigate a comms failure, the satellite modem was unplugged.

ii. Data

https://tsdb.veecharge.com:3000/dashboard/db/garmony?from=1510667048222&to=1510669244859



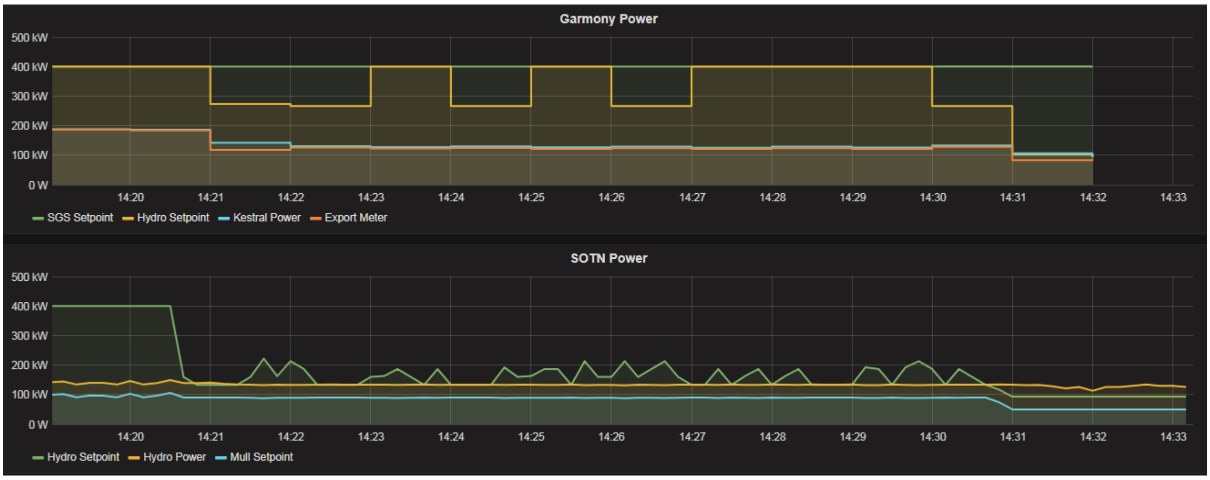
c. ***Test 3—Disable VSCon control to ensure 'Kestrel' generator controller takes control—PASS***

i. Aim & Method

Ensure that if the VSCon were to fail, the 'Kestrel' generator controller will take back control of the hydro plant. Before the VSCon control was to be disabled, the Cranix was set to a constant hydro set point to make observing the change easier.

ii. Data

https://tsdb.veecharge.com:3000/dashboard/db/garmony?from=1510669141670&to=1510669995388



Date: 20/11/2017

Tests

The tests were on a day that heavy rain had fallen overnight, and continued during the day. The output of the hydro was about ~400kW until the tests restricted the output. Chris Baker in attendance.

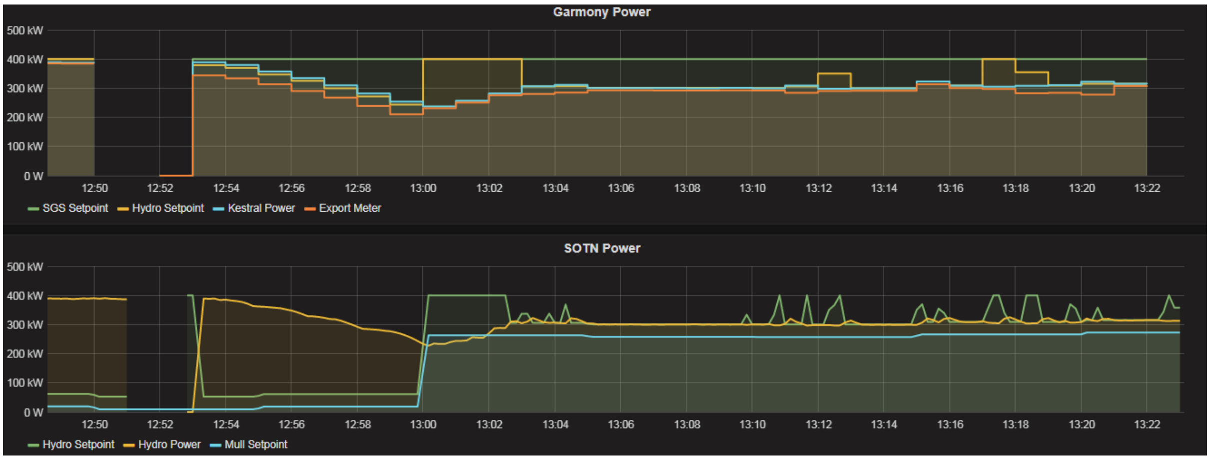
a. ***Test 1—Following a Cranix signal with active curtailment—PASS***

i. Aim & Method

Ensure that the normal operating mode of the SOTN and VSCon are working. Real Mull Cranix data was fed through in real-time. The Cranix was also in charge of the heaters, but the SOTN was setup so that it would send the Cranix market high back to the Cranix as the Grid app demand signal. This effectively means that the comms is tested, but there is no active curtailment of load.

ii. Data

https://tsdb.veecharge.com:3000/dashboard/db/garmony?from=1511182115236&to=1511184187964



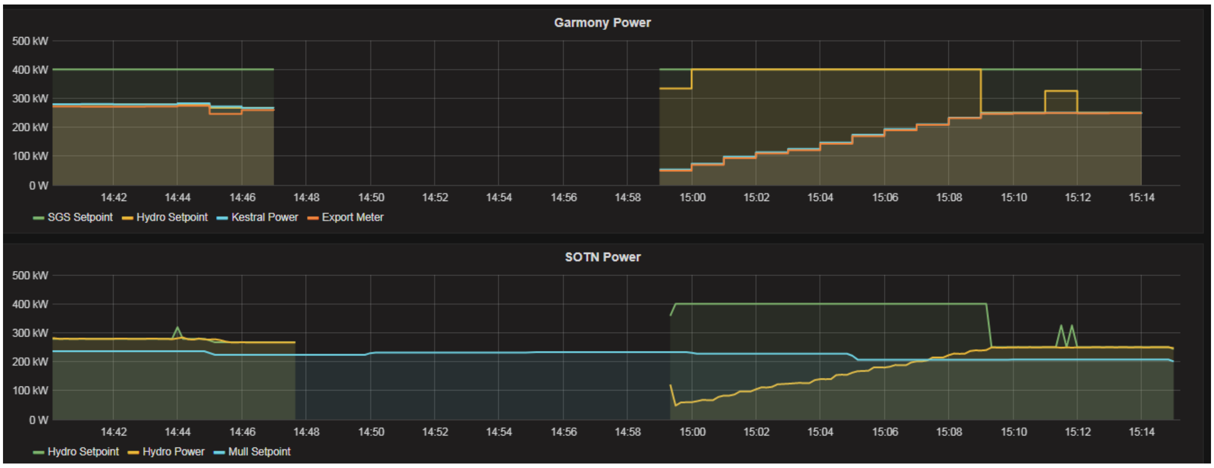
b. ***Test 2—Communications failure between VSCon and SOTN—PASS***

i. Aim & Method

Ensure that the virtual constraint of 50kW would not be violated when the communication failed to the VSCon. Also ensure that normal operation resumes upon the comms being re-established. To instigate a comms failure, the satellite modem was unplugged. This is a repeat of a previous test to ensure the delay in re-establishing comms has been fixed.

ii. Data

https://tsdb.veecharge.com:3000/dashboard/db/garmony?from=1511188806639&to=1511190912454



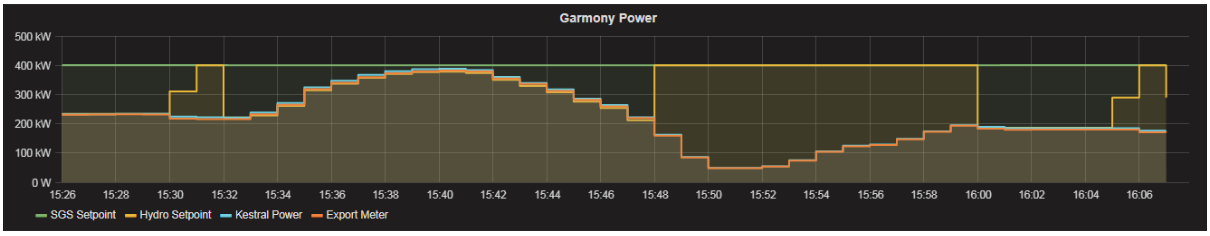
c. *Test 3—Remove VSCon control—PASS*

i. Aim & Method

Ensure that recovery from VSCon control works as expected.

Data

https://tsdb.veecharge.com:3000/dashboard/db/garmony?from=1511191545000&to=1511194071175



Mainland accepts less electricity over 5 minutes, stays for 5min on low level and then jumps back to 400kW. We get SGS signal 100kW, then it's increasing 1kW every second to 400kW. While the signal is changing we should turn on dynamos to have 400kW-SGS usage.

Mainland can accept only 50kW, runs for 5min and after that slowly goes back to 400kW, dynamos should charge to accept generated electricity.

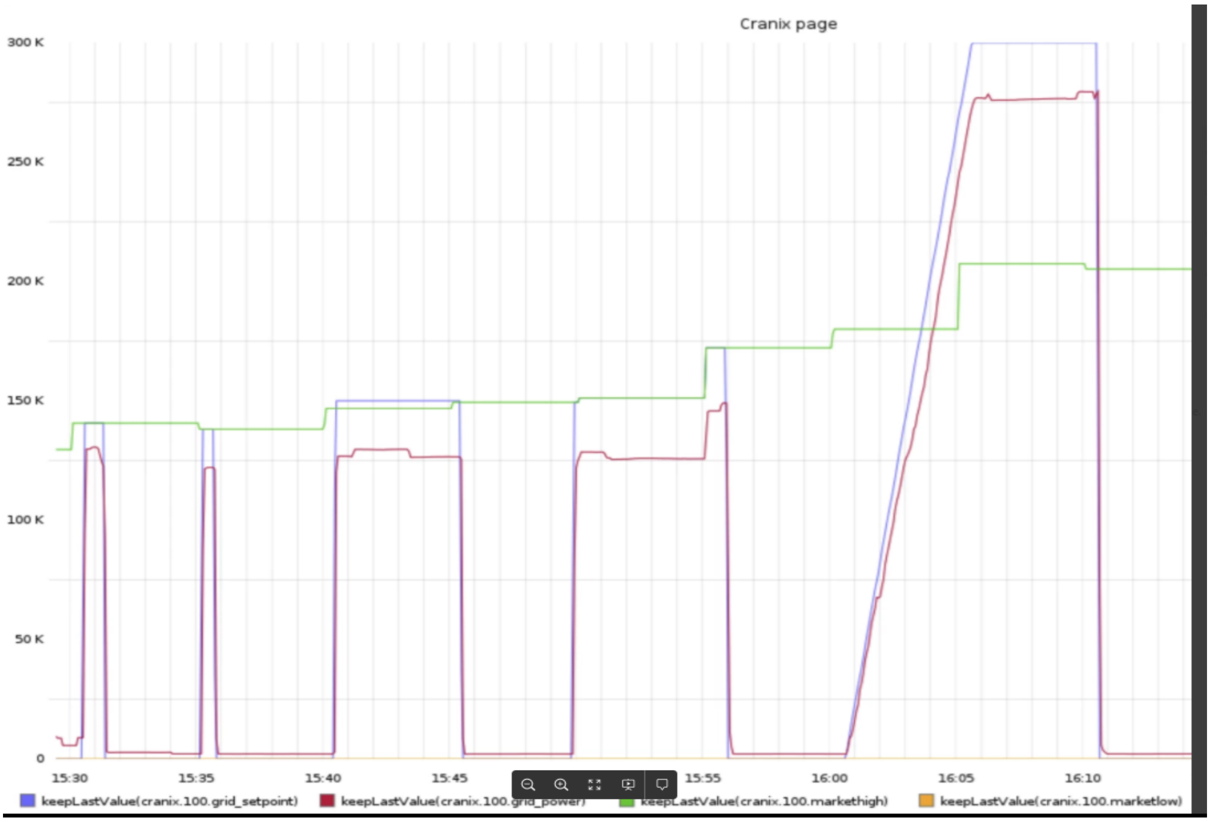
SGS signal drops to 0kW, we should process 400kW with dynamos, we were able to process 330kW.

Date: 22/12/2017

d. *Test 1—VSCon Testing Simulation—PASS*

Mainland accepts less electricity over 5 minutes, stays for 5min on low level and then jumps back to 400kW. We get SGS signal 100kW, then it's increasing 1kW every second to 400kW. While the signal is changing we should turn on dynamos to have 400kW-SGS usage.

Mainland can accept only 50kW, runs for 5min and after that slowly goes back to 400kW, dynamos should charge to accept generated electricity.

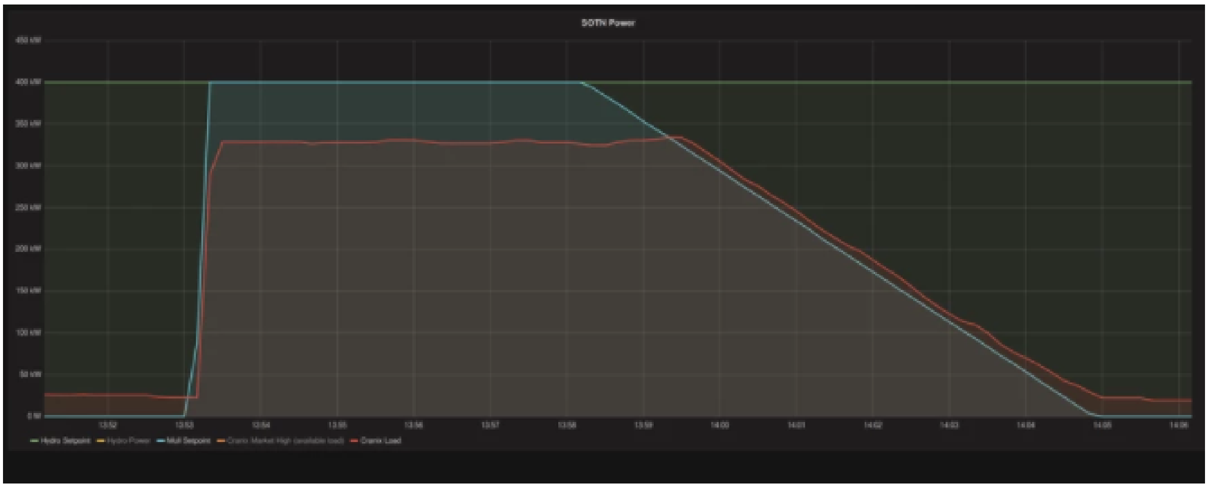


Shows the heaters following a simulated SGS signal, turning on 300kW of load curtailment

1. Green is market high (what we were expecting)
2. Red is how the load it responded

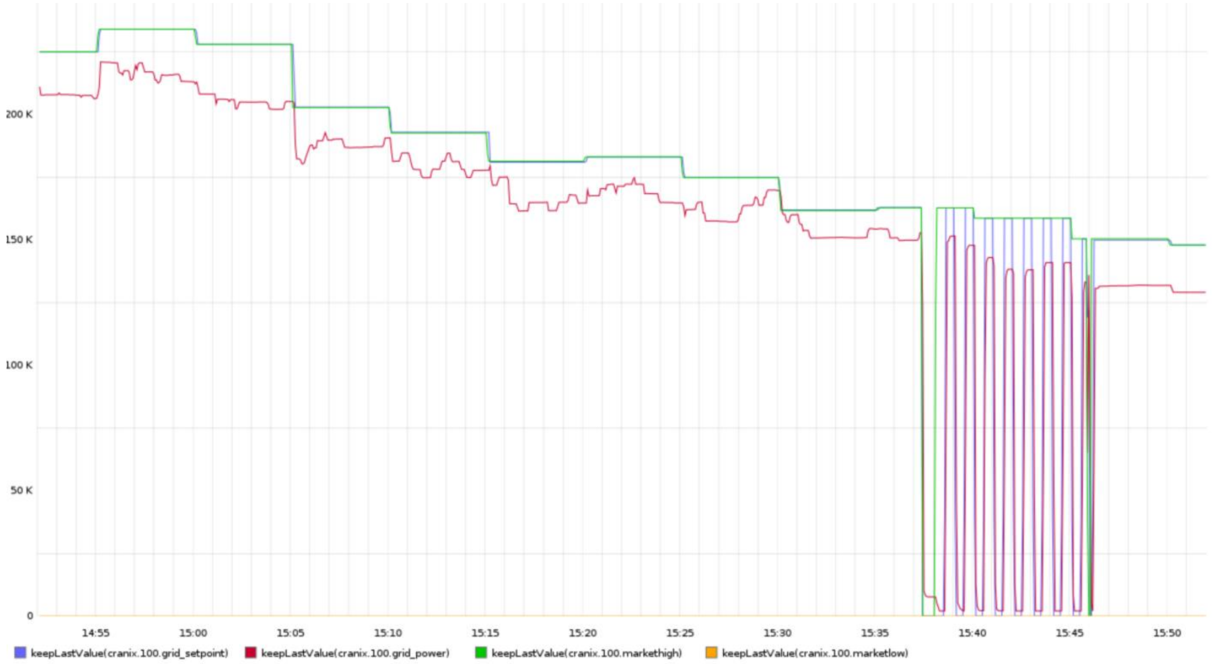
Signal isn't shown on graph. SGS set point is always the same (400kw—not actually changing)

Shows another test to simulate SGS signal drop to 50kW for 5 minutes (Dynamos take 350kW), then to test the signal increase over 5 minutes to 400kW (Dynamos stop charging)



Shows the SGS signal 0kW, capacity is shown as 330kw

There are about 180 connected devices with ~370kW of load. The devices are split between ~900w, 1800, 2700 and 3300. Water heaters omitted from test which accounts for some of the difference between the 370kW online and 330kW maximum power measured.



Green is market high (how many heaters we expect), Red is measured power (how the load responded).

ACCESS Project: Mull Live Following Testing 12/02/18–23/02/18

i. Background

A Continuous Live Following test was to be carried out over a 2-week period. Previous testing achieved satisfactory generation curtailment and proved that the system operated in a safe manner in the event of loss of communications. As a result, these aspects of the system were not required to be tested during the 2 week continuous following period.

ii. Objectives

The test was to meet the following key objectives:

- Load was to process available power during off-peak and peak periods, charging in a regular fashion as frequently as possible.
- Load was to match available power in the event that cumulative heater demand exceeded available power and, if required, charge for an extended period to ensure all heaters met their desired charge state.
- Load was to charge according to normal schedule in the event that no power or insufficient power was available.
- No generation curtailment was to take place.

iii. Tests/Proposals

An outline of the tests and expected results are provided in Table 34:

Table 34 Test Summary

Test	Expected Duration	More detailed description	Expected Observations
Continuous Live Following	2 weeks	VCharge (Cranix) Load is to follow Garmony generation intelligently for a two week period. There are a number of 'Business Rules' which will determine when Storage Heaters charge throughout the test period.	Expected observations include: - VCharge assets processing available generation during off-peak and peak periods, dependent on turbine generation periods. - VCharge(Cranix) load to follow turbine generation when generation is less than the desired cumulative load of heaters. - VCharge assets to charge from turbine production for extended periods if required, due to low production. - VCharge assets to charge regularly when generation is not available or predicted.

iv. Preface

Given the nature of the test, it was predicted that charging may differ somewhat from standard off-peak charging periods. These scenarios would be a result of on-peak generation or generation being less than the total desired load. In these situations, heaters would charge during on-peak hours or for extended periods, respectively.

To ensure that heaters were charging sufficiently, the total power delivered to individual heaters during a given charging period was to be matched to that of the a standard charging period. In essence, based on a regular off-peak charging period for a given heater, that heater should be charged to the same extent even if the charging period has to fall during an on-peak period or is scheduled across a prolonged period due to low turbine production.

Over the weekend before the test was to begin, an essential piece of maintenance was carried out on the VCharge platform to enable the tests. The team responded urgently to the issue and had heaters charging as usual by the end of the weekend.

A number of configuration changes were however made to the platform on Monday 12th February and as a result the beginning of the following test was delayed. During the first two days of following, the platform was restarted to allow for up-to-date configurations to be pushed to the platform. This resulted in a few short periods of unrecorded telemetry and the system performed in a slightly abnormal manner.

v. Results

Based on the expected observations outlined in Table 34, the results are discussed in the following section.

A. Result 1-Following Generation during Off-peak and On-peak periods

Aim:

Ensure that the Cranix Load follows available generation during off-peak and on-peak periods dependent on turbine production periods. When possible, heaters should charge during off-peak periods. However, in the situation where generation is only available during a peak period, heaters should delay charging (where applicable) until turbine production begins.

*The Cranix Load is the total load of all heaters charging at a given point in time

Data:

Off-Peak Following:

Off-peak following occurred due to periods of sustained generation resulting in heaters charging regularly. Additionally, off-peak following occurred when power was available during off-peak periods but not on-peak periods. Off-peak charging was favoured over on-peak charging where possible. It was found that almost all charging periods during the two week continuous following occurred during off-peak.

A period of off-peak following is shown in Figure 50 where heaters charge normally during an afternoon off-peak period. VCharge (Cranix) Load is lower than generation and therefore heaters charge maximally.

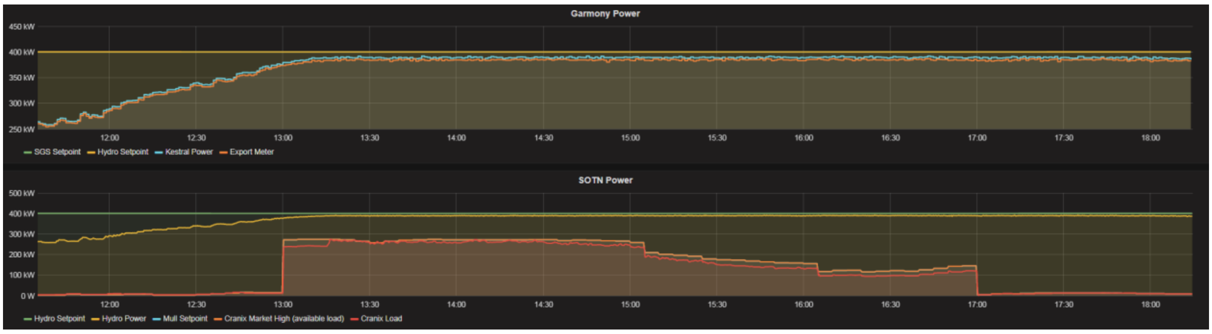


Figure 50 Off-peak Following

On-Peak Following:

On-peak following was to occur when a period of high generation was predicted during an on-peak period and not during the preceding off-peak period. As a result, heaters were to hold off charging until turbine generation began.

On-peak following is shown below. As can be seen a period of no generation occurs during the off-peak period. As a result, heaters waited until the on-peak period to charge as high generation was predicted. The Cranix Load following the Cranix Market High as expected due to generation exceeding the Cranix Market High.

Figure 51 On-peak Following

B. Result 2-Following Generation when Desired Cumulative Load exceeds Generation

Aim:

Ensure that Cranix Load follows generation when the desired Cranix Load exceeds generation. In this case, heaters will process available load even if the cumulative load exceeds available load. As a result, the charging period may be extended to ensure that all heaters are charged sufficiently.

Data:

During a morning off-peak period, load followed turbine production which was less than the Cranix Market High. In this case, heaters did not charge for an extended period as the charge was only slightly below the desired load.

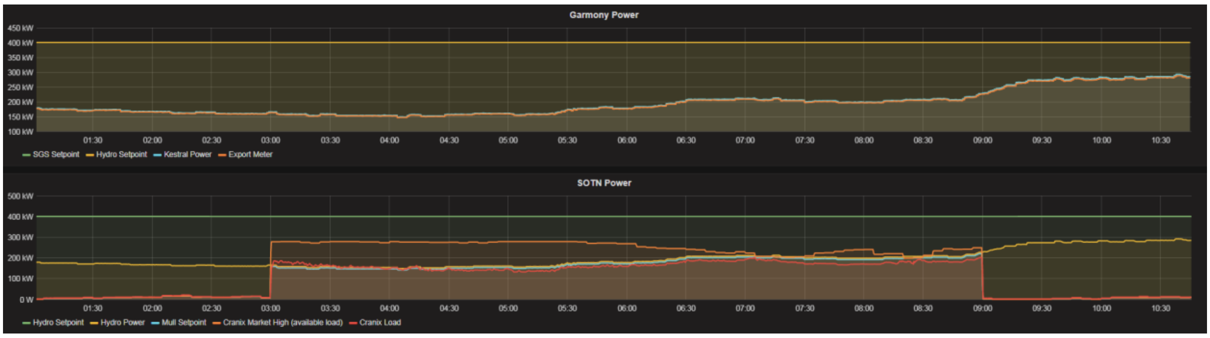


Figure 52 Cranix Load Following Generation

In a second on-peak following event, a similar event occurred. Heaters charged at a slightly reduced cumulative load due to turbine production being less than Cranix Market High.

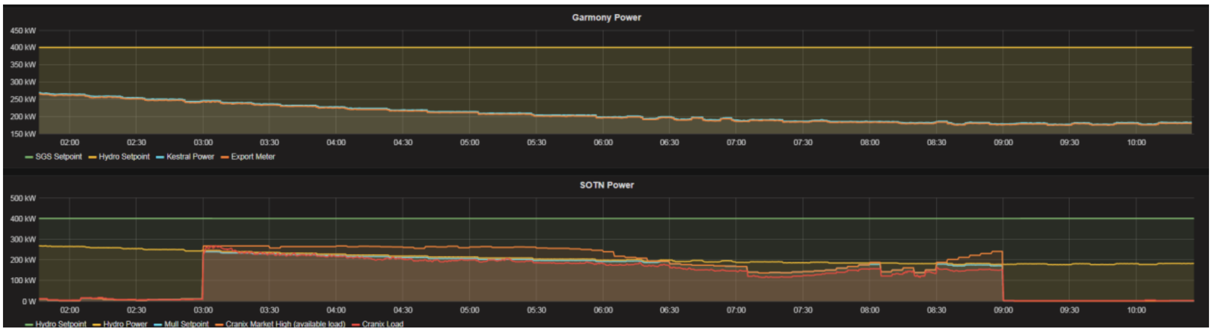


Figure 53 Cranix Load Following Generation 2

In a third scenario, heaters began charging one hour before the beginning of the off-peak period due to declining turbine production.

It should be noted that when generation was below the desired cumulative load of the heaters the actual cumulative load followed the generation rather than the desired cumulative load. Conversely when the generation exceeded the desired cumulative load the actual cumulative load followed the desired cumulative load. This can be seen most clearly when comparing Figure 51 with Figure 52 & Figure 53.

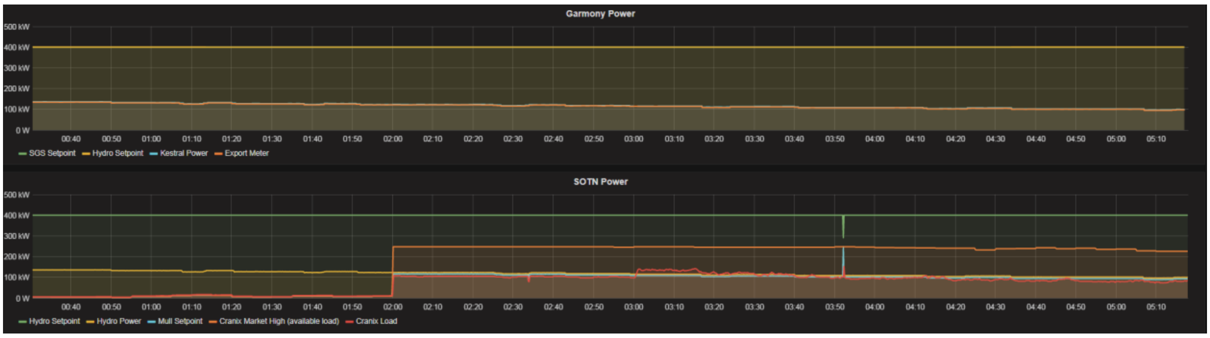


Figure 54 Extended Charging Period due to Low Generation

In Figure 54 above the charge periods were extended so that the heaters could be sufficiently charged. In the example above the generation was below the desired cumulative load. In order to maintain the following tests while also charging the heaters adequately the charge periods were extended.

C. Result 3-VCharge Load to charge regularly when no Power available

Aim:

In the event that the turbine is not producing or producing insufficient power, heaters are to charge regularly ie, no load curtailment.

Data:

A regular off-peak period is shown where no generation is occuring.

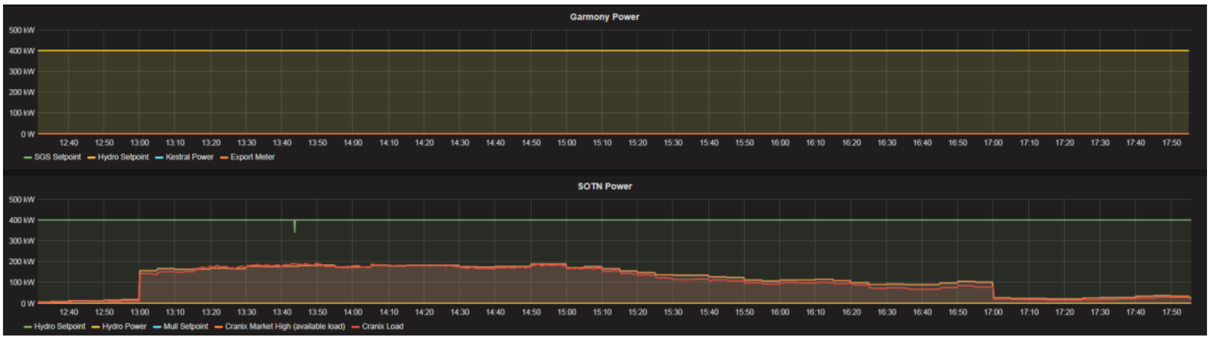


Figure 55 Regular Cranix Off-peak Control

vi. General Test Observations:

Water Heaters

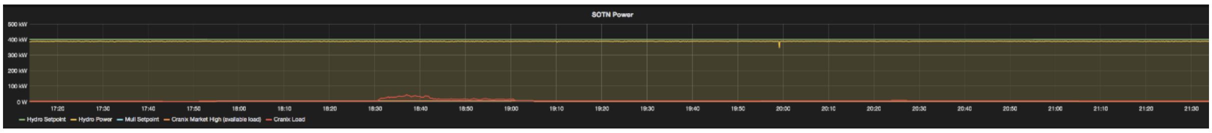


Figure 56 Water Heater Load

Due to previous project requests the water heaters were not included in the tests. These account for between 30 and 45kW of load. Despite these water heaters not being included in the tests they nonetheless appeared on the visualiser as it displays all load connected to the VCharge system.

SOTN Restart Value

When the SOTN was restarted it was noticed that a large negative spike occurred (-1.00GW). Unfortunately, it was not possible to remove these data points from the dashboard view.

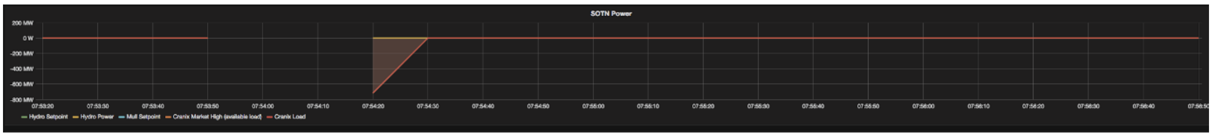


Figure 57 SOTN Restart Value

Cranix Load vs. Cranix Market High

Cranix Load is the total load of all heaters charging at a given point in time. Cranix Market High is the available load which is to be charged based on heater charge state and desired room temperatures for all devices.

There is a discrepancy between the Cranix Load and Cranix Market High due to slightly incorrect heater power values being entered into the platform database during device installation or blown elements in heater.

vii. Summary

In summary, the Continuous Following test was considered a success and the VCharge System displayed behaviours in line with required objectives. A further test is required to finalise the project, namely the SGS Curtailment Signal, which will be carried out during the week commencing 05/03/2018.

ACCESS Project: Mull SGS Response Testing 09/03/18-18/03/18

a. ***Background***

Following the successful live following tests in February a test to show how the VCharge controllable domestic load could be used to respond to a live curtailment signal (SGS signal) from Lochdonhead was required. Previous testing using a simulated SGS signal was successfully completed on 22/12/17 and the final test was to then use the live signal to trigger a curtailment event and assess the response of the VCharge system.

i. Objectives

The test was to meet the following key objectives:

- When the SGS setpoint signal drops below 400 kW (a curtailment event should be triggered), as a result of the under import nearing the Lochdonhead threshold, the VCharge controllable load should respond and turn on so that this threshold is not breached.
- The load should remain until either the SGS setpoint returns to 400 kW or the load cannot take up more energy whereby the heaters will stop charging.
- No generation curtailment was to take place as a result of VCharge's platform.

ii. Tests/Proposals

An outline of the tests and expected results are provided in Table 35:

Table 35 Test 2 Summary

Test	Expected Duration	Expected Observations

SGS Response Test	Intermittently over 2 weeks	Expected observations include: - VCharge assets to be available to respond (tests to be carried out) during off-peak and peak periods. - VCharge (Cranix) load to respond to the SGS setpoint dropping below 400 kW. - VCharge assets to stop charging if they have been on for a prolonged period of time. - VCharge assets to not charge when test is underway and SGS setpoint is 400 kW.

iii. Preface/Detail

In order for the Cranix load to respond to the under import the SGS signal is required. Below is a high level explanation of how the SGS signal is calculated.

The SGS signal is calculated based on the following parameters as confirmed with SGS:

S = the SGS setpoint (kW)

G = Garmony generation (kW)

L = Lochdonhead import-will always be positive (kW)

T = Lochdonhead threshold-the import should not fall below this (kW)

400 kW = maximum generation possible from Garmony

The SGS signal is then calculated as follows:

$$S = L - T + G$$

The Cranix load required can then be calculated using the SGS setpoint and considering the current amount of load already online. It is worth noting that in actual fact the SGS setpoint will actually start responding when the Lochdonhead import (L) drops within 400 kW of the contracted import amount.

iv. Results

Based on the expected observations outlined in Table 35, the results are discussed in the following section.

A. Prolonged SGS Signal Response

The aim of this test was to show how the Cranix load would respond to the SGS signal when it dropped below the 400 kW mark for a prolonged period of time. It was expected that the load would eventually turn off once the heaters were full and could not charge any more.

Peak times were favoured so that VCharge could ensure that the heaters had enough charge to satisfy customers, as the signal rarely dipped below 400 kW and heaters would not charge if in the SGS curtailing mode.

Data:

From Figure 58 it can be seen from the top graph that the SGS setpoint drops from 400 kW to 50 kW (shown by the green line). In response to this the Cranix load (shown in red on the second graph) jumps up to approximately 200 kW.

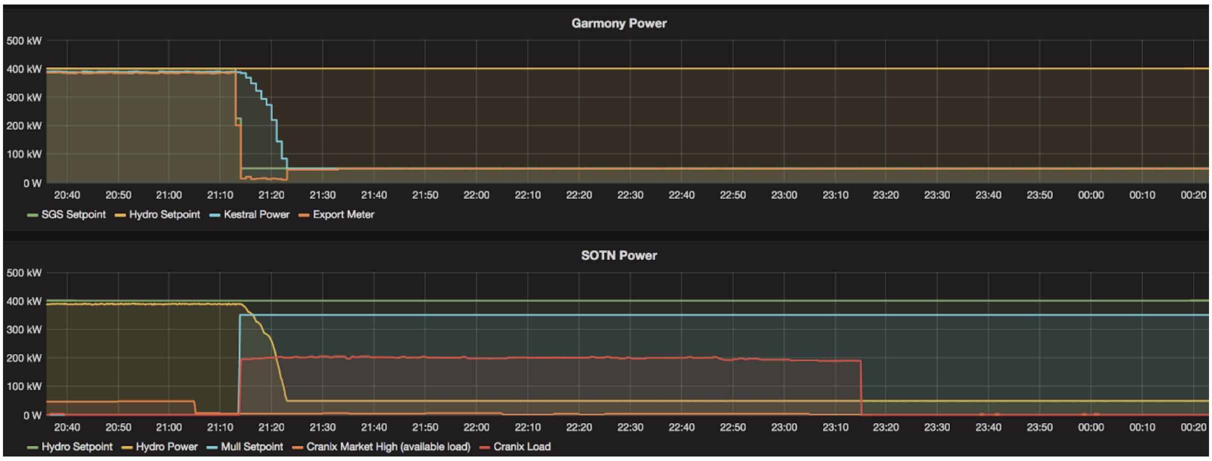


Figure 58 Prolonged SGS response

It can be seen that the Mull Setpoint (blue line on second graph-which the Cranix load attempts to meet) is considerably higher than the Cranix load (Mull Setpoint at 350 kW, in response to the SGS signal at 50 kW). The reason that the load is not reaching the setpoint is that there is not enough available load on the Cranix to meet the setpoint. This may be due to some of the assets already being charged and a general lack of devices due to some decommissions over the lifetime of the project.

At approximately 23:15 the assets stopped charging, likely as many reached their limit, and could not keep charging. This is potentially due to the assets charging in the previous off-peak period.

From this data it can clearly be seen that the assets successfully respond to the drop in the SGS signal by switching on, attempting to hit the Mull Setpoint, and maintain their level for 2 hours.

B. Short SGS Signal Response

In addition to the prolonged SGS signal response it was interesting to see the response of the Cranix load to the SGS signal when the signal dropped for a period of approximately 2 minutes. The load was expected to quickly respond to the SGS signal and then return back to the original point once the SGS signal returned to 400 kW.

Data:

Figure 59 shows how the Cranix load responded quickly to the change in the SGS signal. Once again the Cranix load did not reach the setpoint and stayed around 200 kW.

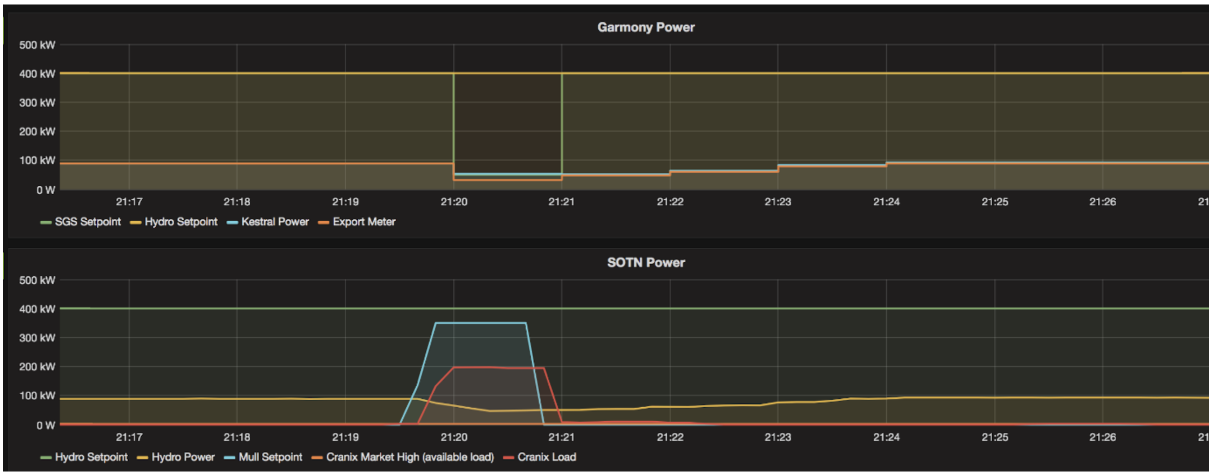


Figure 59 Short SGS response

Once again this data shows how the Cranix load successfully responded to the SGS signal and consequently increased the load on the Cranix.

v. General Test Observations:

In the future it would be useful to have more devices online and connected to the Cranix so that the aggregated load is enough to meet the setpoint. The required load would need to be approximately 400 kW to account for the maximum Garmony generation.

vi. Summary

In summary, the SGS response test was considered a success and the VCharge System displayed behaviours in line with required objectives. This demonstrates how aggregated load can be used to control the amount of energy being imported and if required exported from the island.