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Value of Demand Flexibility for providing Ancillary Services: 
A case for Social Housing in the Irish DS3 market

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Abstract

This paper evaluates the potential of consumer flexibility from a portfolio of heat loads, solar panels and batteries in Social Housing to provide ancillary services. We propose two new ancillary service products: Turn-Up-Demand (TUD) and Turn-Down-Demand (TDD). We ran simulations for a complete year. The buffer-tank scenario provided earnings of £146/year for an average consumer. Finally, we propose a new policy called the Vulnerable Consumer Priority in Administering System Services (VCPASS) and the use of Heat-as-a-Service (HaaS) to fund the replacement of oil-boilers with heat pumps in fuel poor homes with a rate of 9.99p/kWh of heat for a payback period of 15 years.

Keywords: Demand Flexibility in Social Housing; Turn-Up Demand and Turn-Down Demand; DS3 Ancillary Services

1. Introduction

Concern about climate change and declining costs have increased the uptake of renewables such as wind and solar generation. However, the variable nature of such renewables necessitates the use of ancillary services in ensuring that the security of the grid and its power quality is maintained. The Irish all-island electrical power system has integrated the highest levels of non-dispatchable renewable energy into an electrically isolated, standalone electrical grid anywhere in the world, resulting in Northern Ireland achieving 44% renewable electricity consumption in 2019, exceeding its 2020 target of 40% a year early. (DiE and NISRA, 2020).

Electricity is traded between generators and suppliers in the day-ahead and intra-day markets from one day ahead to shortly before real-time. In real-time, the system operator charges or pays market participants depending on if they are short (have a shortage of supply) or long (have a surplus) respectively via the balancing market. This payment (also known as the imbalance price) depends on whether the entire system is short or long. Market participants can participate in the balancing market. However, the response available in the balancing market at any time cannot be guaranteed for the safe running of the system. Furthermore, the system operator requires other services such as voltage regulation, frequency restoration, operating reserve and inertia support to keep the power system stable. This is procured through the ancillary services market.

Ireland and Northern Ireland are already addressing challenges that Europe will likely face in the future. The DS3 (Delivering a Secure, Sustainable System) market is the ancillary services market for the island of Ireland and it is set up to handle very high system non-synchronous penetration (SNSP) – almost entirely wind power, with a target of 95% by 2030 (SEM Committee, 2018; EirGrid and SONI, 2019). SNSP is the percentage of the non-synchronous generation on the system at an instant in time (EirGrid and SONI, 2018c). The system can currently accommodate up to 70% SNSP - this is unprecedented, given that the island of Ireland has no synchronous interconnection to the rest of Europe (EirGrid Group, 2018). DS3 is a pioneering ancillary services market, which includes 14 separate products, spanning response times from 300 milliseconds to 16 hours (EirGrid and SONI, 2017).

About 68% of homes in Northern Ireland use oil boilers, 82% of these are in rural areas, not connected to the gas grid, mainly sparsely distributed and hence not suitable for district heating (Consumer Council, 2013). In Northern Ireland, The Affordable Warmth scheme, Boiler Replacement Scheme and Northern Ireland Sustainable Energy Programme (NISEP) address fuel poverty by using public money to provide energy efficiency measures as well as the provision of natural gas or oil central heating to those at risk of fuel poverty.
(Utility Regulator, 2019). However, with the move to Net Zero by 2050 as legislated by the government (CCC, 2019) and the new ban on gas heating installations in new homes by 2025 (GOV.UK, 2019), further installations of fossil fuel heating systems using public money should be avoided. However, consumers under these fuel poverty interventions must also be protected against high operational cost.

Currently, renewable heating technologies such as heat pumps are expensive both in CAPEX and OPEX due to the high retail electricity price (17.85p/kWh) compared to gas (4.8p/kWh) and heating oil (5.3p/kWh) (Consumer Council, 2019; Utility Regulator, 2020). Recent research carried out by (Le et al., 2019) showed that high temperature cascaded air-to-water heat pump designed to replace fossil fuel boilers by making use of existing radiators could not better gas boilers and high-efficiency oil boilers in terms of operating cost due to the high electricity price.

Nevertheless, flexibility from a portfolio of heat pumps and thermal storage could provide immense value to the grid by providing ancillary services and reduce the need for third-party fossil fuel generators to balance the grid. Most of the wind resource in Northern Ireland is connected to the low voltage network (EirGrid and SONI, 2020) and hence would be better managed by local consumer-owned flexibility. The cost of grid balancing increased the imperfection wholesale cost from €5.22/MWh in 2018 to €10.40/MWh in 2019, leading to higher electricity prices, and this is likely to get worse considering the new 2030 target (SEM Committee, 2019). In Australia, the entry of grid-scale battery (Hornsdale Power Reserve) and EnelX’s DR resource into the frequency and ancillary services market was the major driver behind the 57% reduction in ancillary services cost between Quarter 1 2017 – Quarter 1 2018 (AEMO, 2018). In ERCOT, about half of the contingency reserve is provided by demand response.

(Vorushylo et al., 2018) investigated the benefits of heat electrification in the Irish wind dominated electrical power system and concluded that heat pumps could reduce CO₂ emissions by half compared with gas-fired heating and at least two-third compared with oil-fired heating. However, direct resistive heating is not a viable option for heat decarbonisation as it shows greater environmental impact than gas or oil-fired heating, based on the current grid CO₂ intensity.

There are about 127,400 social homes in Northern Ireland (Housing Executives, 2018). In this paper, we evaluate the impact of flexibility from a portfolio of low carbon heating devices as well as solar panels and batteries in social houses for providing ancillary services. The income from the ancillary services market could help in financing the fuel poverty interventions by bringing forward their payback period of replacing oil/gas-fired boilers with air-source heat pumps (ASHP). The proposed scheme would further reduce CO₂ emissions, provide better heating for consumers, and as well increase the overall system efficiency.

2. Methodology

We propose two innovative ancillary services products that would allow demand-side resources to respond to wind variability, named Turn-Up Demand (TUD) and Turn-Down Demand (TDD), describing the dynamic response of a portfolio of consumer demand to system imbalance. We then provide a detailed description of the services and recommend their implementation in the Irish power system.

The purpose of the proposed new services is to reduce system imbalance to a point where the volumes of other ancillary services needed are significantly reduced, and possibly some services might no longer be needed, enabling demand response to displace fossil fuel generators for balancing the grid. Furthermore, operating electric heating will reduce the level of dispatch-down of wind energy in the system, by increasing demand during those periods. In this work, Storage (Thermal or Electrical) is used as the main source of flexibility. This removes issues such as consumer discomfort since the consumer’s heat demand profile is unchanged. It also reduces the likelihood of imbalance occurring as a result of the payback effect of demand response.

We investigated two different portfolios:

- Portfolio 1: Flexibility from Thermal Devices: in 100,000 Social homes with various electric heating options
- Portfolio 2: Flexibility from Solar Panels / Batteries: in 100,000 Social homes with solar panels/batteries
2.1. Portfolio 1: Flexibility from Thermal Devices:

Heat pump load profiles were sourced from the datasets of the Renewable Heat Premium Payment (RHPP) trial which monitored heat pump loads in about 700 homes (Summerfield, Biddulph and Stone, 2016; Love et al., 2017; Lowe, 2017). The time-series data which includes the electricity drawn and heat generated in watt-hour for both space heating and domestic hot water was recorded at two-minute resolution. 100 Social housing profile with ASHP capacity between 7-14kW and radiator heating were selected from the RHPP dataset and used to simulate the default individual heat pump profile (without storage).

Various low carbon heating scenarios were investigated (see Figure 1):

**SCENARIO HP Default**: This is the default scenario where heat pumps are operating without flexibility or the use of storage devices.

**SCENARIO HB**: Heat pump feeding a heat battery. A heat battery is a type of thermal storage that uses phase change materials (PCM). The PCM cools from liquid back to solid whenever cold water is passed through it, this way the energy stored is released and hot water is produced. The heat battery consumes less space (about a third of a hot water equivalent). The Sunamp Uniq Dual 12 battery was used for modelling. It is capable of replacing a 284L hot water cylinder. It uses 32W standby power, maximum and minimum flow temperatures of 85°C and 65°C respectively and has a hot water outlet temperature of 55°C. It has a heat loss rate of 0.809 kWh/24h. The UNIQ 12 heat battery with immersion heater costs £2641.6. We assumed each house had 2 heat batteries powered by a heat pump.

**SCENARIO BT**: Heat pump feeding a hot water buffer tank for space heating and a hot water cylinder for domestic hot water. For space heating storage, the Dimplex 500L buffer tank (PSW500), which costs £921.50 with a loss rate of 3.024kWh/24hrs was used (Glen Dimplex UK Limited, 2016a). A high-temperature heat pump was used to heat the buffer tank to 85°C, with 55°C flow temperature to the radiators, the buffer tank can store 17.4kW of heat for space heating. For domestic hot water, the ECS210HP-580 210L heat pump cylinder was used. It costs £1346.89 with a loss rate of 1.41kWh/24hr (Glen Dimplex UK Limited, 2016b, 2020a). The buffer tank consumes more space (500L), making it less suitable for typical social housing (90m² floor area).

**SCENARIO SH**: Smart Electric Thermal Storage (SETs) heaters for space heating and Hot water cylinder using immersion heater for domestic hot water. The Dimplex Quantum Heater was used to model the SETs. We assumed each house has one large heater (QM150 - 3.3kW off-peak, 1.3kW peak input, with 23.1kWh storage capacity) and two small heaters (QM100 – 2.2kW off-peak, 0.88kW peak, with 15.4kWh storage capacity) and (QM070 – 1.56kW off-peak, 0.63kW peak, with 10.9kWh storage capacity) (Glen Dimplex UK Limited, 2019). The QM150 costs £965.71, the QM100 costs £816.77, while the QM070 costs £739.92 as at the time of writing (Glen Dimplex UK Limited, 2020b, 2020d, 2020c). The Dimplex Quantum Water Cylinder QWCd (210L, with a loss rate of 1.41kWh/24hr working with a 3kW Immersion heater input) was used to model the domestic hot water (Glen Dimplex UK Limited, 2016c). The QWCd 210 costs £1302.68 as at the time of writing (Glen Dimplex UK Limited, 2020e). The storage heaters charge with Economy 7 tariff signal – which offers cheaper electricity for seven hours at night (1 am – 8 am in winter and 2 am – 9 am in summer).

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**Figure 1.** Summary of the heat options considered
The three storage heating options were then subjected to the imbalance signal for the Irish power system in 15 minutes resolution for the period Oct. 2018 – Sept. 2019. Figure 2 shows the simulation control logic for thermal flexibility. During periods of positive system imbalance (generation exceeds demand), the excess imbalance is used to meet the heat demand of the houses or used to charge up their storage when there is no demand. When there is a negative system imbalance, the storage is used to meet the demand, and if the storage is depleted, heat loads are turned down for a maximum of 3 hours. A counter is used to keep track of heat energy that has been turned down. Whenever the system is back to a positive imbalance within 3 hours of a previous turn-down, the heat loads are turned on to compensate for the previous turn down. After three hours, any remaining deficit turn-down is assumed to be unneeded and ignored. Using this strategy, the discomfort to the consumer is reduced. The heat loss within each period is applied to each consumer storage after each iteration.

![Image](image_url)

Figure 2. Simulation control logic (Heat Pump and Thermal Storage)

2.2. Portfolio 2: Flexibility from Solar Panels / Batteries:

Consumer load profiles were sourced from the dataset of the Low Carbon London (LCL) Project (UKPN, 2014). A filter was applied to select only profiles with annual demand between 4000 – 7000kWh. A 2kW PV SolarEdge PV panel was installed at the Ulster University test house. The PV generation was monitored using the SolarEdge monitoring platform and was used in the simulation to represent the generation profiles for the PV panels installed in the portfolio under NI weather conditions. Hence the assumption is that all houses have the same PV generation profile. SonnenBatterie ECO 8.4 which cost £6200 (vat. Inc.) with 4kW capacity, 2kW inverter charging and discharging power and a round-trip efficiency of 83% was used to model the battery (sonnenBatterie, 2019).

Figure 3 shows the simulation control logic for PV and Battery. The main difference from the simulation of Portfolio 1 is that base loads cannot be turned down, they can only be reduced by the stored energy in the battery, hence flexibility for both TUD and TDD is provided by solely the battery and solar panel. The solar panels are also operated in a manner that sends excess energy to the grid rather than charge the battery during TDD events. We ran the simulation for a complete year (October 2018 to September 2019) using a time series of system imbalance at 15 minutes resolution to determine the response. Preference was given to calling the heat portfolio first to respond to imbalance signals, while the PV-Battery portfolio was called to respond to the remaining system imbalance. By using real heat pump, PV and imbalance data, this methodology guarantees that the results are as close to a real-life situation as possible. Any uncertainty is very low since the simulation was considered for a full year, which caters for seasonal and diurnal changes.
3. Results:

3.1. Investigating the heat scenarios as options for decarbonisation:

We investigate the impact of the three heating scenarios (Heat Battery, Buffer Tank and Storage Heaters) when compared to the default scenario (No Storage). Figure 4 shows the average hourly heat demand under the various scenarios while Table 1 shows the annual aggregated demand under the three scenarios. It shows a reduction in demand by 3.53% for the heat battery, an increase of 9.61% for the buffer tank and increase of 57.83% for the storage heater. The role of thermal storage is to shift the demand, making it flexible, not to reduce or decrease demand, as the storage is not a generator. However, the little reduction in heat demand for the heat battery is due to some unpaid TDD. The increase in heat demand for the buffer tank is primarily due to the larger heat loss requiring more heat demand to be made up, while the storage heater requires more than 50% additional heat demand since it has the lowest coefficient of performance and a significant part of the heat stored during the night is eventually lost. Furthermore, a wide-scale rollout of storage heaters would cause issues with network capacity due to its lower coefficient of performance.

![Figure 4. Average hourly heat demand for each scenario](image-url)
Table 1. The Annual Aggregated heat demand under the various scenarios

<table>
<thead>
<tr>
<th></th>
<th>HP Default</th>
<th>Scenario HB</th>
<th>Scenario BT</th>
<th>Scenario SH</th>
</tr>
</thead>
<tbody>
<tr>
<td>Annual Aggregated demand (MWh)</td>
<td>353,126</td>
<td>340,656</td>
<td>373,380</td>
<td>589,293</td>
</tr>
<tr>
<td>% Demand Reduced or Increased</td>
<td>-3.53%</td>
<td>9.61%</td>
<td>57.83%</td>
<td></td>
</tr>
</tbody>
</table>

Figure 5 shows the total monthly heat demand under various scenarios. The demand is greatest in the winter months (December, January and February) and lowest in the summer months (June, July and August) under all scenarios.

Using a time-series of the CO₂ intensity in the All-Island grid during the period under simulation available at (EirGrid, 2019), we calculate the potential savings in CO₂ emissions compared with oil-fired heating which is currently used. The CO₂ intensity of oil was assumed as 0.3kgCO₂/kWh. As a result of the large heat demand, storage heaters produce relatively little reduction in CO₂ emissions (21.2%), when compared to the continued use of oil boilers as can be seen in Table 2 and Figure 6. Hence, storage heaters are a poor option for heat decarbonisation.

The default heat pump scenario (without storage) reduces CO₂ emissions by 53.4%, while the heat battery and the buffer tank scenarios provide CO₂ reductions of 57.22% and 53.4% respectively. The greatest reductions were achieved in the heat battery scenario because more demand is shifted to times of high wind and low CO₂ intensity in the grid. Furthermore, the heat battery outperforms the buffer tank, due to its lower heat loss and hence less need to turn up heating demand during the day. The rest of the paper discusses the response of the other scenarios apart from the storage heater.

Table 2. Reduction in CO₂ Emissions from the three scenarios when compared to Oil-Fired Heating

<table>
<thead>
<tr>
<th></th>
<th>Oil-Fired Heating</th>
<th>HP Default</th>
<th>Scenario. HB</th>
<th>Scenario. BT</th>
<th>Scenario. SH</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO₂ Emissions</td>
<td>264,845</td>
<td>123,404</td>
<td>113,297</td>
<td>123,350</td>
<td>208,471</td>
</tr>
<tr>
<td>(tonnes)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>% Reduced</td>
<td>53.4%</td>
<td>57.22%</td>
<td>53.43%</td>
<td>21.29%</td>
<td></td>
</tr>
</tbody>
</table>
3.2. Response of the Storage Scenarios to System Imbalance Signals:

Figure 7 shows the response of the various scenarios to the imbalance signal on a typical day. During the day (March 1st). Between 12:45 a.m. – 7:30 a.m., there was more generation than demand (up to about 586MW by 6:45 a.m.) as reflected on the Imbalance Signal (in yellow). In response, the portfolios turned up demand, using the excess generation to charge up their storage. Initially, Portfolio 1 was called upon, both scenarios (Heat battery (HB) and Buffer Tank (BT)) were able to meet the volume of imbalance in the system providing up to 205MW at 4:30 a.m. Then the amount of response Portfolio 1 could provide decreased gradually with the heat battery scenario decreasing faster due to the lower overall storage space of 19.79 kW compared to the 24.73 kW allocated to the buffer tank in the modelling. As a result, Portfolio 2 (PV_Response) was called upon which was able to provide up to 200MW response until the TUD event finished by 7:30 a.m.

By 7:30, the system had negative imbalance (demand greater than generation). Both portfolios were then called upon to reduce the demand, this was done using the charged storage during the rest of the day.

Figure 7. Response of the Scenarios to the Imbalance Signal

The total annual response of the scenarios to TUD and TDD events is given in Table 3, while the monthly response is given in Figure 8. Both the heat battery and buffer tank have an approximate amount of annual TUD / TDD response, the PV/Battery scenario provided significantly more TUD response than TDD, because base loads were not turned down. It can also be seen that the battery provided more TUD response than the
buffer tank or heat battery. This is because the battery can charge using the grid’s imbalance or excess solar energy and discharge itself several times in the day. The total response is greatest in the winter months (December, January and February) for the thermal devices, while the battery maintains good response volume in the summer.

**Table 3.** Total Response for TUD and TDD Events for the Year

<table>
<thead>
<tr>
<th>Scenario</th>
<th>TUD (GWh)</th>
<th>TDD (GWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Heat Battery (HB)</td>
<td>101</td>
<td>110.2</td>
</tr>
<tr>
<td>Buffer Tank (BT)</td>
<td>131.7</td>
<td>108.6</td>
</tr>
<tr>
<td>PV/Battery (PV)</td>
<td>229.4</td>
<td>54.5</td>
</tr>
</tbody>
</table>

![Figure 8. Total Monthly Response (Dispatched) of TUD and TDD for each scenario](image)

We plot the average hourly response at each time of the day for TUD and TDD events for the scenarios in Figure 9. From the graph, we can see that Turn-Up Demand events usually occur at night with 1 a.m. - 3 a.m. peak for the thermal devices and 1 a.m. - 7 a.m. for the battery. Turn-Down Demand response occurs mostly during the day with peak times between 4 pm – 8 pm for thermal devices.

![Figure 9. Average Hourly Response (dispatched) showing response times for TUD and TDD](image)
3.3. Performance of Demand Response for Ancillary Services:

Table 4 lists the 14 current DS3 services, their time scales, and scalar values.

<table>
<thead>
<tr>
<th>DS3 Product</th>
<th>Time Scale</th>
<th>Temporal Scarcity Scalar Values</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>0-50% SNSP</td>
</tr>
<tr>
<td>Synchronous Inertial Response (SIR)</td>
<td>300ms</td>
<td>1</td>
</tr>
<tr>
<td>Primary Operating Reserve (POR)</td>
<td>5-15 sec</td>
<td>1</td>
</tr>
<tr>
<td>Secondary Operating Reserve (SOR)</td>
<td>15-90 sec</td>
<td>1</td>
</tr>
<tr>
<td>Tertiary Operating Reserve 1 (TOR1)</td>
<td>90-300 sec</td>
<td>1</td>
</tr>
<tr>
<td>Tertiary Operating Reserve 2 (TOR2)</td>
<td>5-20 min</td>
<td>1</td>
</tr>
<tr>
<td>Replacement Reserve (Synchronised) (RRS)</td>
<td>20-60 min</td>
<td>1</td>
</tr>
<tr>
<td>Replacement Reserve (De-Synchronised) (RRD)</td>
<td>20-60 min</td>
<td>1</td>
</tr>
<tr>
<td>Ramping Margin 1 (RM1)</td>
<td>1-3 hour</td>
<td>1</td>
</tr>
<tr>
<td>Ramping Margin 3 (RM3)</td>
<td>3-8 hour</td>
<td>1</td>
</tr>
<tr>
<td>Ramping Margin 8 (RM8)</td>
<td>8-16 hour</td>
<td>1</td>
</tr>
<tr>
<td>Steady State reactive Power (SSRP)</td>
<td></td>
<td>1</td>
</tr>
<tr>
<td>Fast Frequency Response (FFR)</td>
<td>2-10 sec</td>
<td>0</td>
</tr>
<tr>
<td>Fast Post Fault Active Power Recovery (FPFAPR)</td>
<td></td>
<td>0</td>
</tr>
<tr>
<td>Dynamic Reactive Response (DRR)</td>
<td></td>
<td>0</td>
</tr>
</tbody>
</table>

We investigate the performance of demand response in providing ancillary services in terms of the available volume for each product time frame. Figure 10(a-f) shows plots of the amount of response available and the amount dispatched during different timeframes for various events throughout the year. As concluded from the Freedom Project which trailed the response of heat pumps to frequency services (Turvey, Clarke and Calder, 2018), heat pumps can be turned down remotely within 10 seconds. However, it takes up to 5 minutes to turn-up. As a result, participation in POR, SOR, and TOR1 is limited to TDD events, hence the lower availability within this period (Figure 10a). Generally, the available volume decreases for services with longer time frame, from about 400MW when been called upon for TOR2 (Figure 10b) to a maximum availability of only 71MW after 8 hours, as seen in Figure 10f. Hence, we can conclude that demand response from heat loads is more suited for providing operating and replacement reserves (POR -RRD). Its response volume is moderate for RM1 and low for RM3 and RM8.

We also investigated whether the portfolio responding to TUD and TDD signals would be available during frequency events as another measure of performance. The normal operational frequency range is between 49.8Hz and 50.2Hz. Frequency excursions outside these could cause serious problems and may lead to blackout if not properly and quickly arrested. Historic system frequency data at five seconds resolution was obtained from the system operator. System frequency dropped below 49.8Hz on thirty-four occasions between October 2018 – September 2019. The lowest nadir was 49.4Hz. As these were all turn-down events, the heat pumps could have provided primary and secondary operating reserves.

Figure 11 shows the response (TDD) of each scenario during each frequency event. The measure in this case is availability since the dispatched volume depends on the exact amount the system operator needs to bring the system frequency back to normal, as well as the choice of portfolio. The three scenarios showed a high availability rate, there was just one occasion where all three scenarios were not available for response. This is
due to the prolonged use of the portfolio, exhausting the available response just before the frequency event occurred.

Figure 10. Available Response within each product timeframe

Figure 11. Response of the Scenarios to Frequency Events
3.4. Value of Demand Response for Ancillary Services:

The current DS3 system is organised based on regulated tariffs with an expenditure cap. Service payments are based on the available volume of response that is technically realisable during a trading period, irrespective of whether it was dispatched by the system operator. This is applied on a per-system service and per-trading period basis (EirGrid and SONI, 2018a). For each trading period (30 minutes duration), the trading period payment is given as follows:

Trading period payment (£) = Available Volume (MW) \times Payment Rate (£/MWh) \times Scaling Factor \times Trading Period Duration (hr). \hspace{1cm} \text{Eq. (1)}

The Scaling factor includes the Product Scalar, the Performance Scalar and the Temporal Scarcity Scalar. DS3 uses the temporal scarcity scalar to incentivize the provision of ancillary services when the system needs it most (at times of high SNSP). The product scalar incentivises faster provision of FFR and enhanced delivery of other services (POR, SOR, TOR1), while the performance scalar rewards a high level of performance and ensures lower payments for unreliable providers (EirGrid and SONI, 2017).

The structure of the current DS3 services is suited to fossil fuel generators. The Available Volume (hence the payment structure) is based on the higher of either the difference between the generator’s registered capacity and the final physical notification, or the registered capacity and physical dispatch position. This guarantees these generators significant income, whether they are scheduled in the day-ahead market, are later dispatched by the system operator, or were not even dispatched at all. This principle disincentivises a move to clean energy which is paradoxically one of the main objectives of the programme.

As a result of the “payment based on availability” principle, the payment rates are kept to within the allowed DS3 budget. As demonstrated in our work, demand response (which provides a cleaner way of grid balancing) cannot function under this structure since the available volume in any period depends on the dispatch instruction in previous periods. It is difficult or not possible to declare a fixed capacity for the demand response portfolio since the volume of response available is not constant. Furthermore, calculating their payment using the dispatched quantity at the current payment rate would severely reduce their income and ensure they cannot be profitable. Hence, we recommend the development of a separate rate for TUD and TDD services that would guarantee fair remuneration based on their dispatched quantity if the current regulated system is to be continued. Other DS3 reserve services can also be harmonised under this new structure to ensure fair remuneration for all technologies. This would prioritise demand-side units, which can neither declare their available volume in certainty nor need to participate in the day-ahead markets, to provide system services.

However, the Single Electricity Market (SEM) Committee has put up a consultation for the transition to a market-based approach at the end of the current regulatory arrangements (by April 2023) (SEM Committee, 2020), in line with the European directive for market-based procurement of balancing capacity. Article 6 of the Regulation 2019/943 of the clean energy package states that: the contact for balancing capacity should not be concluded more than one day before the provision of the balancing capacity, except for special cases where a derogation is granted for contracting a maximum of 30% of the balancing capacity for a maximum of one month in advance of delivery (The European Commission, 2019). This is effectively requiring daily auctions for balancing capacity. These auctions are usually held a day ahead of energy market openings in other European countries (SEM Committee, 2020), hence market participant would know their system services commitments before the opening of the day-ahead market, and demand response providers would not need to participate in the day-ahead market, provided they are prioritised in the auctions.

As mentioned earlier, the imbalance settlement price is paid by suppliers and generators for deviating from their market position. In addition to other network tariffs, it is used to fund system operator actions in balancing the grid. However, from Figure 12, we see that the imbalance prices are lower at night times when there is positive system imbalance, as well as a higher level of dispatch-down of wind energy, contrary to the main objective of the DS3 program - to reduce the level of dispatch down of wind energy. Using the imbalance price as a basis for calculating payment of ancillary services in each trading period will not incentivise the provision of ancillary services at night time when the system needs it most. Furthermore, a minimum amount of remuneration must be guaranteed and agreed upon to ensure providers of ancillary services are motivated to be reliable while maintaining profitability. Between October 2018 – September 2019, the average day-ahead market price was £50.28/MWh while the average imbalance settlement price was £53.35/MWh. Operating in DAM is technically less challenging than providing balancing and ancillary services at very short time resolution.
In the absence of a tariff structure that works for demand response, we have assumed a TUD/TDD price of £60/MWh, since this just above the average value of participating in the day-ahead or balancing market. We also assume a rate of £70 when SNSP is between 60-70% to reflect scarcity. This assumed rate compares favourably to National Grid’s Demand Turn Up service, which paid large energy users and generators an availability fee of £1.50 and average utilisation price of £65.33/MWh in 2018 to increase demand or reduce generation overnight and weekend afternoons in the summer with average notice period above six hours. (National Grid and WPD, 2016; NationGridESO, 2019).

Successful implementation of this service relies on the dispatch process. National Grid did not procure Demand Turn-Up in 2019 (after three years of the program) due to the inefficient offline dispatch process (emails) causing a long notice period for delivery and small volume procured (NationGridESO, 2019). Bigger challenges are expected for aggregated residential demand than for industrial sites; hence we recommend the use of an automated dispatch and monitoring process right from the inception of the program.

We calculate the earnings using the assumed rates based on the dispatched volume and the SNSP during each trading period. Table 5 shows the total annual earnings for the three scenarios, while Figure 13 shows the graph of the total monthly earnings for the three scenarios. The earnings are low for the thermal devices during the summer (June, July, August and September), while the PV/Battery provide a good amount of earnings throughout the year. An aggregator should consider having both portfolios to ensure continuous revenue throughout the year. The annual revenue for the Heat battery scenario is £12.82 million, for the Buffer Tank scenario is £14.63 million and the PV/Battery scenario is £17.48 million.

Table 5. Annual Earnings for each scenario

<table>
<thead>
<tr>
<th>Portfolio Earnings</th>
<th>Heat Battery (HB)</th>
<th>Buffer Tank (BT)</th>
<th>Solar Panels / Battery (PV)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Earnings per House</td>
<td>£128.20</td>
<td>£146.30</td>
<td>£174.80</td>
</tr>
<tr>
<td>Portfolio Earnings</td>
<td>£12.82 million</td>
<td>£14.63 million</td>
<td>£17.48 million</td>
</tr>
</tbody>
</table>

Figure 12. Average Hourly System Imbalance vs Imbalance Price
3.5. Business Model for the use of Demand Response for providing Ancillary Services:

The transition towards a low carbon economy is more likely to affect vulnerable consumers who do not have access to capital to invest in heat pumps and thermal storage. A business model solution which could address this issue is Heat-as-a-Service (HaaS). An aggregator with access to capital would fund the replacement of oil-fired boilers with heat pumps and storage, and charge consumers a fixed rate per kWh of heat delivered. In Table 6, we work out the total cost of such scheme and the rate per kWh of heat the aggregator could charge to achieve a payback period of 15 years. For the calculations, we have used the tariff for large energy users and assumed the heat pump cost £5,700 for both the indoor and outdoor units (Daikin UK, 2017). We have also assumed the oil boiler has an efficiency of 95% and cost £5,000. We did not include the setup costs: such as cost for aggregation, communication, contract, and market fee.

Table 6. Calculations for average price/kWh of heat for an aggregator offering HaaS.

<table>
<thead>
<tr>
<th></th>
<th>Oil Boiler</th>
<th>HP Default</th>
<th>Buffer Tank</th>
<th>Heat Battery</th>
</tr>
</thead>
<tbody>
<tr>
<td>Annual Cost of Electricity/Oil</td>
<td>£380</td>
<td>£630</td>
<td>£383</td>
<td>£352</td>
</tr>
<tr>
<td>Cost/yr. (for a 15 year payback period) of (Heat pump &amp; Storage) / Oil Boiler</td>
<td>£333</td>
<td>£378</td>
<td>£530</td>
<td>£711</td>
</tr>
<tr>
<td>Annual Earning from Ancillary Services</td>
<td>-</td>
<td>-</td>
<td>£146</td>
<td>£128</td>
</tr>
<tr>
<td>Deficit (Costs - Earnings)</td>
<td>£713</td>
<td>£1,008</td>
<td>£767</td>
<td>£935</td>
</tr>
<tr>
<td>Annual Heat sold (kWh)</td>
<td>7,187</td>
<td>7,565</td>
<td>7,675</td>
<td>7,020</td>
</tr>
</tbody>
</table>

Switching to heat pump without flexibility will cost an average consumer 13.32p/kWh of heat if using the current retail price of 17.85p/kWh of electricity. With flexibility from provision of ancillary services and using a tariff for large energy users (which an aggregator would be eligible for), the cost is reduced to 9.99p/kWh for the buffer tank scenario and 13.32p/kWh for the heat battery scenario. This puts low carbon heat from the buffer tank (hot water) at the same cost as an oil boiler. These calculations are based on a 15-year payback period. However, the cost of the buffer tank and heat battery scenarios could be lower as DS3 payments will increase in line with progress to SN5P of 95%. Additionally, further system value could be monetised such as
the provision of congestion management and local voltage control, as well as using surplus wind energy that would have been dispatched down.

An example of a more consumer-centric version of HaaS is the Bristol energy living lab trial. The project allows consumers to select customized plans such as room-by-room, hour-by-hour heating options, guaranteeing certain comfort levels subject to fair-use (to prevent consumers from opening their windows and letting the heat out). The provider can then calculate a fixed monthly cost using data collected from the smart heating control system (Chard et al., 2019).

4. Conclusion:

We proposed two new ancillary services products specifically for demand response called Turn-Up Demand and Turn-Down Demand and price structures for the services. Various heating options for a portfolio of 100,000 social houses were simulated to respond to these two services for a complete year. Heat Pumps with Heat Batteries, Heat Pumps with Buffer Tanks and Solar Panel / Electrical Batteries were used to provide ancillary services for both Turn-Up Demand and Turn-Down Demand events. In another scenario, we simulated the use of storage heaters operating off-peak with Economy 7 signal. The results show that storage heaters are not the best option for heat decarbonisation. With a base price of £60/MWh and scalars applied depending on the SNSP level, the revenue for an average consumer is £128/year for the Heat Battery scenario and £146/year for the Buffer Tank scenario. This revenue will increase as the system moves to 95% SNSP by 2030, as there will be more trading periods were higher scalars would be applied. Other revenue sources should be investigated, such as the use of the flexibility of heat devices to provide local congestion management to the distribution system operator (DSO) as well as surplus wind energy that would have been otherwise dispatched down. Stacking up these multiple revenue sources would shorten the payback period.

The revenue for an average consumer is £175/year for the PV/Battery scenario. The response times for solar panels/batteries is complementary to that of heat pumps / thermal storage. Furthermore, the PV/Battery scenario provided more TUD response particularly in the daytime and summer months where the response from the heating scenarios was lowest. Hence, the aggregator and system operator would find having both portfolios a good option.

While buffer tanks are cheaper, they consume more space and have higher heat loss. Heat Batteries, while being more expensive, have lower heat loss and can fit into compact spaces which is very suitable for social housing. Furthermore, in terms of CO₂ emissions, the heat battery has greater reductions (57%) than the buffer tank (53%), making it environmentally the best option.

Current fuel poverty interventions in Northern Ireland are not fit for the future. For example, NISEP is funded through the DSO’s public service obligation that places a flat charge per kWh of electricity consumed for all electricity consumers. This has helped in replacing 12,320 heating systems and boilers since 2010 (Utility Regulator, 2019). As mentioned earlier, spending public money on fossil fuel heating systems cannot continue. A move to renewable heating without monetising all available system value would be expensive and would mean that fewer interventions could be made under the current budget.

The transition towards low carbon economy is more likely to affect vulnerable consumers who do not have access to capital to invest in heat pumps, solar panels and batteries. Electrification of heat and transport is likely to result in increased network costs, which would disproportionately affect vulnerable households. Therefore, it makes sense to prioritize the use of flexibility from such consumers in providing system services.

We term this policy, the Vulnerable Consumer Priority in Administering System Services (VCPASS). If adopted, it would allow the Northern Ireland Housing Executive which currently manages the Affordable Warmth Scheme and Boiler Replacement Grant to fund the replacement of oil/gas boilers with heat pumps and thermal energy storage with the proceeds of £14.6 million / year for 100K consumers. This could be done by a partnership with a third party, such as an aggregator company with capital to fund the replacement of oil boilers with heat pumps and thermal storage while providing heat as a service with a rate of 9.99p/kWh of heat, if using a buffer tank and 13.32p/kWh of heat if using a heat battery, assuming a 15 years payback period.

Aggregated Generation Units (AGU) (which are Fossil Fuel Based) and Industrial Demand Side Units (DSU) (demand response) were included on the proven technology list for DS3 system services for FFR - RM8 from the 2017 prequalification Trial (EirGrid, 2017; Eirgrid and SONI, 2019a). Although Residential Demand Side
Management (RDSM) and Solar Power are not yet accepted, they have been included in the 2019 DS3 prequalification trial at the time of writing (Eirgrid and SONI, 2019b). We recommend the development of a separate rate for TUD and TDD services that would guarantee fair remuneration based on their dispatched quantity. This is vital to encouraging the entry of the RDSM technology into the DS3 market.

Further research might be needed to investigate the integration of the demand-side response services investigated here with the newly setup Trans European Replacement Reserve Exchange market (TERRE) as the market develops, to see, the available replacement reserve ( > 15 minutes response time) that can be traded, the reliability as well as the price dynamics between the TUD/TDD and the TERRE market.

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