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Role and value of FUSION concept in supporting cost effective electricity system decarbonisation

FUSION Project Report

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1. Executive Summary

Project FUSION aims at supporting the transition of Scottish Power Energy Networks (SPEN) from the traditional Distribution Network Operator (DNO) role to a new Distribution System Operator (DSO) role, and subsequently provide a paradigm for such transition to all UK DNOs. The project trials commoditised local demand-side flexibility through a structured and competitive market, based on the Universal Smart Energy Framework (USEF). FUSION has demonstrated the additional value of USEF-facilitated demand-side flexibility trading against the conventional paradigm for coordinating such flexibility. This report addresses the benefits of implementing USEF (relative to business-as-usual practices) to manage local distribution network constraints and to support wider national grid balancing requirements to facilitate cost effective transition to zero carbon future.

1.1. Benefits of FUSION in local distribution networks

The first objective of this report is to investigate the contribution of flexibility to the local security supply and the benefit in deferring upgrades in the local distribution network. The FUSION trial area in East Fife is supplied from two primary substations, St Andrews and Leuchars, through 17 high-voltage (HV) feeders, 505 distribution transformers and over 279 km of HV cables and overhead lines.

Based on the actual annual load profiles and the reliability of flexibility service delivery observed during the trial, the contribution of flexibility to security of supply is quantified by determining the achievable reduction in peak demand and the resulting improvements in network reliability parameters, including customer interruptions (CI), customer minutes lost (CML) and Expected Energy not Supplied (EENS). The Effective Load Carrying Capability (ELCC) approach is then applied to quantify the potential increase in demand enabled by flexibility while keeping the EENS level at the same level as without flexibility.

As an example, for one of the three feeders where flexible assets are connected, the additional demand that could be accommodated, if flexibility is available, is found to be around 1.8% of the feeder peak demand. The other two feeders with trialled flexibility assets were not loaded as close to their rated capacity as the first one, and therefore the corresponding benefits are found to be minimal in the short term.

The network analysis suggests that the contribution of flexibility to the security of supply of the local distribution network will be mostly affected by the following factors:

- Size of flexibility compared to peak demand: for higher flexible capacity its relative security contribution generally reduces, as the width of the relevant peak demand window becomes greater. For example, for the St Andrews site the maximum contribution of the 305 kW flexibility resource to peak reduction was 82% of its capacity, while the contribution of the 10 kW resource was 100%.
- Number of flexibility assets: security contribution of a small number of large flexibility assets is lower than the contribution of a larger number of smaller assets with the same total capacity. For example, the maximum contribution of 291 kW of flexible capacity connected to the Leuchars primary is lower if there is only one asset (9%) than if multiple smaller assets are assumed (25%).
- Location of flexibility in the network: flexibility assets located closer to normally open points (NOP) can provide a greater security contribution than those closer to the beginning of a feeder.
- Level of congestion during an outage: the higher the congestion during an outage, the lower the security contribution, as the relevant peak demand window becomes wider and longer (similar to the impact of the size of flexibility i.e., more flexible capacity is needed to deal with the higher congestion).

- Shape of the profile: in general terms, the security contribution of flexibility with a relatively flat demand profile would be lower than with a peakier profile, for similar reasons as for the effect of size of flexibility. For illustration, at feeder 19324 for two different days with the same peak demand, the security contribution is greater for the day with narrower peak (56%) compared to the contribution of 25% when the peak is wider.

The ENA Common Evaluation Methodology (CEM) tool is used to quantify the monetary benefits resulting from the deployment of USEF-based flexibility relative to the BaU-based flexibility scenario, resulting from both network upgrade deferral and CML reduction. Potential savings from USEF-based flexibility that could be achieved on one of the congested feeders are estimated at about £695-728, or 13% above the benefits of the BaU-based flexibility. These savings should be contrasted to the additional enabling cost of USEF-based flexibility compared to BaU flexibility. The assumed volume of flexibility is the same in both BaU and USEF scenarios, while the incremental cost associated with enabling USEF over BaU, was estimated at £147k, which is incurred by both aggregators and the DNO[1].

Assuming the average additional benefit in the USEF scenario of £711.50, the additional enabling cost of USEF would be annulled by the USEF benefit achieved on 207 HV feeders, where flexibility could enable network upgrade deferral (if flexibility is only used for management of HV feeder congestion). When the total observed benefits of flexibility of about £5k (associated with both network upgrade deferral and CML reduction) are compared to the prices for availability and utilisation of flexibility services used in the FUSION trial, the total cost of about £2m significantly exceeds the benefits, which is expected given the innovation aspect of FUSION and the need to incentivise flexible providers to participate in the trial.

Also, although the magnitude of additional USEF-based flexibility benefits is rather modest, it has to be noted that they refer to the current situation in a small number of feeders, some of which are loaded at a relatively low level. In the future, as electricity demand increases as a result of electrifying heat and transport sectors, the benefits of FUSION can be expected to increase to a much more significant level, both because of higher network loading and due to FUSION potentially unlocking additional sources of flexibility, which was the key premise for the whole-system benefit assessment presented in the following section.

Another potential benefit of flexibility may be reflected in enabling earlier demand/generation connections relative to the counterfactual connection schedules. However, this effect is outside of the scope of this report.

1.2. Benefits of FUSION to the whole UK electricity system

The next objective of the report is to quantify whole-system benefits of rolling out the FUSION concept nationwide. The main premise of this analysis, based on discussions with project partners, is that FUSION can unlock residential flexibility that would otherwise have a difficult route to market and potentially remain a largely untapped resource.

Figure 1 below presents the whole-system cost savings achieved by the deployment of the FUSION concept (with respect to a counterfactual without FUSION), across two different future scenarios developed by National Grid, System Transformation (ST) and Consumer Transformation (CT), and two time horizons (2035 and 2050). Driven by the whole-system nature of this analysis, the resulting effects on total system cost are disaggregated into multiple components of cost savings, distinguishing between generation investment cost (both low-carbon and conventional), storage investment cost, interconnection investment cost, operating cost and distribution network investment cost.

[1] Provided by SPEN as additional cost of £87k for DNO and £30k for each of two aggregators.

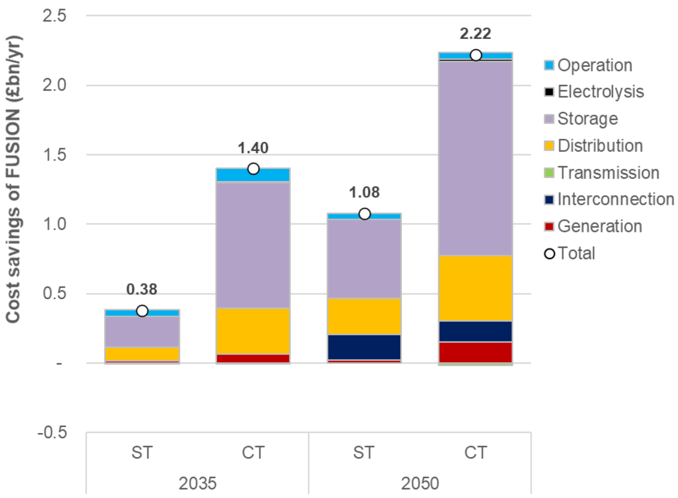


Figure 1. Whole-system cost savings achieved by FUSION

Deployment of FUSION can deliver cost savings that materialise in various system segments, including reduced requirements for distribution network reinforcement, reduced requirement for peaking capacity, and reduced requirement for other means of flexibility such as interconnectors. These savings are driven by the ability of FUSION to utilise localised flexibility to shift electricity demand from peak to off-peak periods as well as follow the output of variable renewables.

System benefits are found to vary in magnitude depending on the scenario and time horizon, with higher benefits in the CT than in the ST scenario, and a significant increase between 2035 and 2050. This is driven by the increasing volume of electrified transport and heating demand and a higher absolute level of flexibility. In the ST scenario the benefits of FUSION more than double between 2035 and 2050 (from £0.38bn/yr to £1.08bn/yr). In the CT scenario the value reaches £1.40bn/yr already in 2035, due to faster electrification of heat and transport, increasing further to £2.22bn/yr in 2050.

In order to provide a more granular view of GB-wide implications of FUSION deployment in distribution networks, Imperial's representative network modelling approach is used with 23 statistically representative networks, based on the output DSR utilisation profiles from the whole-system model. Potential additional GB distribution network reinforcement deferral in 2035 is estimated between £8.1-8.7bn for CT and ST scenarios, respectively, for USEF compared to BaU-based flexibility. In 2050 this reduces to between £2.1-4.4bn. Highest savings are observed in suburban networks followed by urban and rural networks.

These savings differ from the distribution network savings presented in Figure 1 as these are: i) cumulative rather than annualised, and ii) represent a strategic rather than incremental investment paradigm (i.e., a network element is assumed to be strategically upgraded to accommodate any future load increase rather than replaced with the next largest size/capacity).

Figure 2 provides a breakdown of distribution network reinforcement cost savings achieved by FUSION across the two system scenarios and time horizons. Savings are disaggregated per component level of the distribution network (LV: low-voltage lines, DT: secondary substations, HV: high-voltage lines, PT: primary substations, EHV: extra-high-voltage lines, GT: grid substations). Main benefits are associated with delayed or avoided network reinforcement, while enabling additional connections that can increase the utilisation of distribution networks. Given the ambitious assumptions on electrification of heat and transport, in the long term (2050) there will be a need to reinforce a significant proportion of the distribution network infrastructure given the significant increase in electricity demand, which could result in potentially lower value of flexibility in 2050. Nevertheless, its value in deferring medium-term reinforcement will be significant.

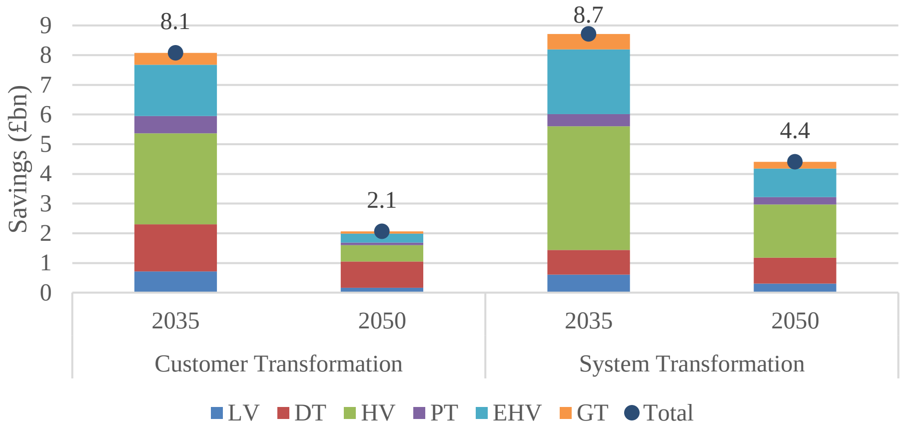


Figure 2. Distribution network reinforcement cost savings achieved by FUSION

Finally, FUSION will also deliver benefits in terms of improved security of supply, which are not factored in the above analysis. Figure 3 presents an illustrative example of the security of supply benefits of FUSION for one selected feeder in the trial network area. Benefits are quantified through the reduction in the expected energy not supplied (EENS), when compared to both "no flexibility" and BaU scenarios. Benefits of FUSION in this case arise purely from improved availability rates of flexible providers; the positive effect would be much more prominent if FUSION was also able to unlock additional flexible capacity, as assumed in the whole-system analysis.

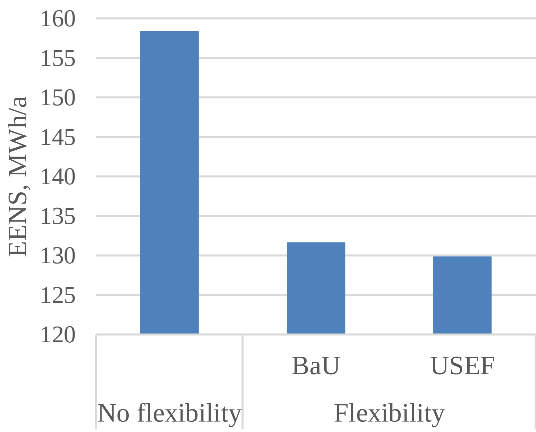


Figure 3. EENS benefits achieved by FUSION

1.3. Cost-benefit analysis of FUSION

Based on the estimates of gross economic system benefits, net benefits of FUSION have been evaluated in two ways: i) by quantifying annual net system benefits as difference between gross system benefits and the cost of implementing FUSION, and ii) by estimating the Net Present Value (NPV) for the future trajectory of whole-system benefits and costs of FUSION.

The cost of implementation and enablement of residential flexibility required to deploy FUSION is estimated to be between 40% and 70% of gross whole-system benefits across various scenarios, resulting in net system benefits of FUSION ranging from £216m/yr in the ST scenario in 2035 to £654m/yr in the CT scenario in 2050.

The present value (PV) of FUSION deployment cost was estimated at £3.2bn in the ST scenario and £11.5bn in the CT scenario. The PV of corresponding whole-system benefits was found to vary in the range between £6.2bn and £17.3bn across the two system scenarios. This resulted in a positive NPV of net system benefits of FUSION totalling £2.9bn and £5.8bn for the ST and CT scenarios, respectively. This suggests a positive business case for FUSION from the whole-system perspective due to its gross benefits exceeding the implementation and enablement cost.

Finally, if gross system benefits are expressed per unit of flexible capacity or per unit of flexible energy use, this provides an estimate of a justifiable upper limit for the cost of implementing FUSION in residential Demand Side Response (DSR) resources. Based on the modelling results, FUSION would provide positive a net system benefit if its deployment cost is lower than £31-51/MWh of flexible energy demand, or lower than £32-42 per kW of flexible capacity per year.

2. Introduction

2.1. Background: Emerging decarbonisation challenges in the UK

Project FUSION aims at supporting the transition of Scottish Power Energy Networks (SPEN) from the traditional Distribution Network Operator (DNO) role to a new Distribution System Operator (DSO) role, subsequently providing a paradigm for such transition to all UK DNOs. To achieve that, the project trials commoditised local demand-side flexibility through a structured and competitive market, based on the Universal Smart Energy Framework (USEF). USEF is a standardised framework that defines products, market roles, processes, data exchange, interfaces and control features and has recently gained great momentum in supporting the extensive changes that are currently taking place in electricity markets, driven by the wide decarbonisation of energy systems and the electrification of transport and heat sectors. The project has demonstrated the additional value of USEF-facilitated demand-side flexibility trading against the conventional paradigm for coordinating such flexibility.

Specifically, energy systems in the UK and beyond are currently undergoing fundamental changes, mainly driven by the continuously increasing levels of greenhouse gas emissions and the associated environmental and climate change concerns. Numerous governments have taken significant initiatives in response to such concerns. In 2017, in its advice to the UK Government on future carbon budgets, the Committee on Climate Change (CCC) has emphasised the importance of decarbonising the power sector and recommended that the aim should be to reduce the carbon intensity of power generation from the current levels of around 350 gCO2/kWh to around 100 gCO_2/kWh in 2030 and potentially 25 gCO_2/kWh in 2050 [1]. More recently, in 2021, the Department for Business, Energy & Industrial Strategy unveiled its plans to fully decarbonise the UK electricity system by 2035 [2], 15 years ahead of the overall energy system, to enable wider decarbonisation. This trajectory towards reaching net-zero carbon emissions necessitates fundamental changes at both generation and demand sides of the energy systems, through the accelerated deployment of zero-carbon generation sources and the decarbonisation of transport and heating sectors, respectively.

At the generation side, this decarbonisation is already underway through the widespread deployment of renewable and other zero-carbon generation sources. Recent analysis of the generation mix required for a net-zero GB system indicates that it may be required to install as much as 100 GW of offshore wind generation capacity to meet the net-zero target [3]. However, many of these sources, especially wind and solar generation which constitute the dominant renewable energy technologies in the UK, are inherently characterized by high variability and limited predictability and controllability. Their power output is not only extremely variable but is also zero during periods of low wind speed or no sunshine. Furthermore, increased shares of renewables (i.e., inverter-based power generation) in the capacity mix reduce the system inertia which is provided by the stored kinetic energy of the rotating mass of the power generators' turbines. With this reduction in system inertia, any imbalance between supply and demand will change system frequency more rapidly, challenging the stability of the system [4]-[5]. Furthermore, at present nuclear generation is inflexible, implying that it cannot contribute to the balancing burden of the system.

At the demand side, significant decarbonisation of the heat and transport sectors is expected in the coming decade [6]. Traditional technologies for the satisfaction of heating and transportation consumers' requirements (gas / oil fired technologies for heating and internal combustion engines for transportation) are based on the intense consumption of fossil fuels and the emission of a significant portion of the total greenhouse emissions. In combination with the ongoing and future decarbonisation of electricity generation systems, strong motives arise for the electrification of these technologies. Recent technological developments in the automotive and heating sectors have enabled this transition through the deployment of electric vehicles (EV) and electric heat pumps (EHP) [6]. Nevertheless, due to the natural energy intensity of heating and transportation loads, the environmental and energy security benefits of this transition are accompanied by a considerable increase in electricity demand. Going further, the electrification of heat and transport sectors will lead to disproportionately larger demand peaks than the increase in the total electrical energy consumption, due to the temporal patterns of users' heating and driving requirements [7]. Finally, it is expected that this paradigm change will greatly intensify the interaction between electricity and heat supply systems, while also opening opportunities for intermediate energy vectors such as hydrogen.

Challenges that decarbonisation of energy generation and demand presents for electrical power systems are related to how these systems are currently operated and planned. At the short-term operation timescale, given that demand is largely treated as an inflexible load, the required flexibility for balancing the system through ancillary services is provided solely by conventional dispatchable generators (mainly gas generators). In a future system with an increased penetration of renewable and nuclear generation, these conventional generation units will be producing much less energy, as absorption of the low-cost and CO_2-free production of renewable and nuclear generators will be prioritised in the merit order. However, given that renewable generation is variable and intermittent and nuclear generation is currently inflexible, the conventional generators would need to remain synchronised in the system and operate part-loaded as a back-up energy source (e.g. operating in periods of low wind speed or low sunshine) and flexibility provider (since renewable and nuclear generators not only have very limited capabilities to provide system balancing services, but they are also making system balancing more challenging). This under-utilisation of conventional generation assets implies that the cost efficiency of their operation will reduce. Furthermore, their cost efficiency will be aggravated by the increase of their start-up and shut-down cycles, driven by the system variability and power ramping requirements. Several previous studies have evaluated the system benefits of enhanced flexibility in energy systems with high shares of renewables, where various flexible solutions such as energy storage, demand-side response (DSR), network expansion, flexible generation technologies and sector coupling can support cost-efficient integration of renewables [8].

Furthermore, a sufficient level of frequency response is needed to deal with sudden loss of supply to the system (e.g., because of a failure of a large generator / interconnector or a rapid change in demand or renewable generation) to keep the system frequency within its statutory limits. To date, the frequency response service can only be provided by synchronised conventional plants which need to operate part-loaded and produce at least at the minimum stable generation level (MSG). This reduces the ability of the system to absorb electricity production from renewables or other low-carbon technologies. This means that due to balancing challenges, renewable generation assets are also under-utilised and thus may not achieve their CO_2 emissions reduction potential.

Moreover, the large-scale connection of renewable generation to transmission and distribution grids creates certain network challenges, such as thermal congestion and increased voltage levels, which threaten the security of these grids. The most critical network challenges are increased short-circuit currents in urban areas and voltage rise effects in rural areas [9].

At the long-term planning timescale, given that demand side is again treated as an inflexible load, the current paradigm lies in predicting this demand and building sufficient generation and network capacity (given certain security margins) to cover it. The disproportional increase in demand peaks with respect to the increase in overall energy consumption, induced by the envisaged electrification of heat and transport sectors, means that a significant amount of new generation and network capacity needs to be built in the coming years, and this capacity will be significantly under-utilised as it will be used only to cover the increased demand peaks. This constitutes a huge challenge particularly for DNOs, who are the very focus of the FUSION project, since it implies the need for extensive reinforcement of their area networks in order to cope with the increasing demand peaks driven by electrification of transport and heat.

Given the above factors, under the historical operation and planning paradigm, the utilization of generation and network assets will be significantly reduced, while the total system costs will be dramatically increased, especially beyond 2025 where the electrification of heat and transport will require extensive and capital-intensive investments.

2.2. Role of demand-side flexibility in emerging electricity systems

Driven by these fundamental challenges associated with the decarbonisation of energy systems and elaborated in Section 2.1, the need of bringing forward new sources of flexibility has been established in the UK policy framework, to ensure that the low- or zero-carbon system can efficiently maintain secure and stable operation going forward. Several flexibility resource options are available at system level, including flexible generation technologies, energy storage, demand-side response (DSR) and cross-border interconnection to other systems. However, particular interest has been recently attracted by local, distributed forms of demand-side flexibility [7].

These include different types of flexible loads, distributed energy storage, electric vehicles with smart charging (and potentially vehicle-to-grid) capabilities, flexible distributed generators, as well as flexible technologies that lie in the border of different energy sectors. Integration between electricity and other energy vectors, particularly heat and transport, presents novel and unique opportunities to make use of cross-vector flexibility to support the integration of low-carbon generation technologies and to significantly reduce the cost of decarbonisation. Previous analysis by researchers from Imperial College London demonstrated that various alternative heat decarbonisation pathways may be feasible, such as those based on heat networks, hydrogen, biogas, or electrified heating, each with their own cost implications and a rich set of interactions between energy vectors, opening opportunities to utilise the flexibility across multiple vectors [10].

This particular interest is because suitable coordination of such distributed forms of demand-side flexibility has the potential to support system balancing in a future with an increased penetration of renewable generation and therefore to reduce the curtailment of renewable generation and the efficiency losses of conventional generation, as well as limit peak demand levels and therefore avoid capital intensive investments in under-utilized generation and network assets. More specifically, as discussed in [1], the potential value streams of such distributed forms of demand-side flexibility are:

- Deferral or avoidance of distributed network reinforcements / expansions, by deploying flexibility to manage network constraints;
- Reduced investment in low-carbon generation, as the available renewable resources and nuclear generation can be utilised more efficiently enabling the system to reach the carbon target with less low carbon generation capacity or a less expensive mix of low-carbon technologies;
- Potential savings in generation capacity investments, including a reduced need for peaking plant capacity (because of demand peak reductions), and a reduced need for flexible, back-up capacity (as such generation capacity can be replaced by these flexible technologies in the provision of balancing and ancillary services); and
- Reduced system operation cost, as various reserve and frequency response services are efficiently provided by new, less expensive, flexibility sources rather than by conventional generation.

In other words, intelligent coordination of such flexibility sources in both operation and planning timescales can reverse the trend of asset utilization reduction and enable a more cost-effective transition to the low-carbon future. Specifically, a recent study based on Imperial College's modelling assessed the whole-system value of distributed behind-the-meter flexibility [11]. One of the main conclusions was that in a low-carbon electricity system residential flexibility (including smart electric vehicle charging, smart appliances and smart heating) can create whole-system cost savings of up to £6.9bn, while at the same time delivering savings per household of more than £200 per household per year. A major part of the value came from smart operation of heating systems, amounting to £3.9bn.

2.3. Project FUSION

The very focus of project FUSION lies in realizing the huge potential of local, distributed forms of demand-side flexibility in emerging decarbonised electricity systems, which has been elaborated in Section 2.2 above. Going further than that though, this project also appreciates that in the deregulated environment, the realisation of this potential requires a suitable market design framework that treats demand-side flexibility as a commodity and captures its multiple value streams for the whole electricity system. In this context, the project deploys the USEF framework that defines clear products, market roles, processes, data exchange, interfaces and control features in an integrated fashion, in contrast to the conventional paradigm for coordinating demand-side flexibility.

Through this USEF framework, the FUSION concept lies in transforming traditional DNOs to DSOs, who operate local flexibility markets to enable valuable trading of flexibility from demand-side resources. The overall ambition of FUSION is to enable DNOs as well as other market participants to unlock and access the value of localised flexibility resources in a competitive and transparent manner. It is expected that FUSION will bring about a range of benefits for customers, who will become empowered to commoditise their flexibility thanks to new routes to market for existing and emerging flexibility providers in the distribution network. FUSION is expected to unlock flexibility in the distribution network, allowing it to be procured by a range of market actors including aggregators.

2.4. Structure of the report

The key interest for the DNOs is in using local flexibility to alleviate localised network congestion without requiring costly and time-consuming network reinforcement, as discussed in Section 3. Nevertheless, establishing a flexibility market will provide benefits not just to the local network, but also to the whole energy system, as elaborated in Section 4. Utilising the flexibility potential unlocked by FUSION can deliver significant economic and environmental benefits to the wider energy system, by allowing for a more efficient integration of renewable energy sources and facilitating the uptake of low carbon technologies. To enable this, a cost-benefit analysis is provided in Section **Error! Reference source not found.**. Section 6 summarises the main conclusions of the report.

3. Establishing Local Network Benefits

The aim of this section is to investigate the contribution of locally procured flexibility in FUSION trials to security of supply and evaluate the benefit of flexibility for local distribution networks through network upgrade deferral.

3.1. Approach

Contribution of the trialled flexible assets to security of supply is quantified on the trial network in East Fife, considering the current state of network connectivity, loading and reliability. Security contribution of flexible assets is established in two steps:

- Step 1: by superimposing demand reduction that could be achieved by flexibility for a typical peak day profile. This assumes a fully reliable delivery of the flexibility.
- Step 2: by using peak demand reduction from step 1 as capacity, and the availability of flexibility (based on trial data) to establish the effective contribution of flexibility to security of supply. The Effective Load Carrying Capability (ELCC) approach is used to establish the potential increase in demand enabled by enhanced flexibility that would maintain the same level of risk as with the original demand level without flexibility. This increase in demand represents the ELCC. The ELCC approach considers the reliability rates of flexibility providers that were observed empirically during the trial. Network reliability analysis, including power flow calculations, is carried out for both intact and N-1 outage and loading conditions and the results are presented in this section.

The Common Evaluation Methodology (CEM) tool is used to assess merits of deferring network reinforcement by employing flexibility solutions (Section 3.6). Within the trial area (which is smaller than the entire DNO licence area) the impact of trialled flexibility assets is compared between BaU and USEF-based paradigms. The additional cost of implementing USEF is not considered in Section 3. As discussed in Section 3.4, availability and utilisation prices from trials have been used.

Section 4.2.4 scales up the analysis of benefits from deferred network reinforcement to the GB level in the 2035-2050 horizon by using the representative networks approach (i.e., statistical representation of distribution networks).

3.2. Trial distribution network

The High Voltage (HV) distribution network in East Fife, the location of the FUSION trial, is supplied from two primary substations: i) St Andrews Primary (with 10 feeders), and ii) Leuchars Primary (7 feeders). Main network characteristics are given in Table 1.

Table 1: Size of East Fife local network

Parameter	Value
Primary sites	St Andrews Primary and Leuchars Primary
Distribution transformers	505 transformers rated from 5 to 1000 kVA
HV cables	1426 sections with total length of 110 km
HV overhead lines	703 sections with total length of 169 km
Circuit breakers	88 CBs at GM sites
Sectionalisers	83 sectionalisers at PM sites
PMARs	11 PMARs at PM sites
Fuses	13 fuses at PM sites
Switch fuse	58 switch fuses at GM sites
Switches	301 switches
Switch line	311 at 11 kV and 4 at 33 kV

Based on the annual demand profile, the Load Duration Curve (LDC) is constructed for the trial area as shown in Figure 4, which has been normalised for power and duration. The annual load factor for this LDC, also equal to the area under the normalised LDC, is 61%.

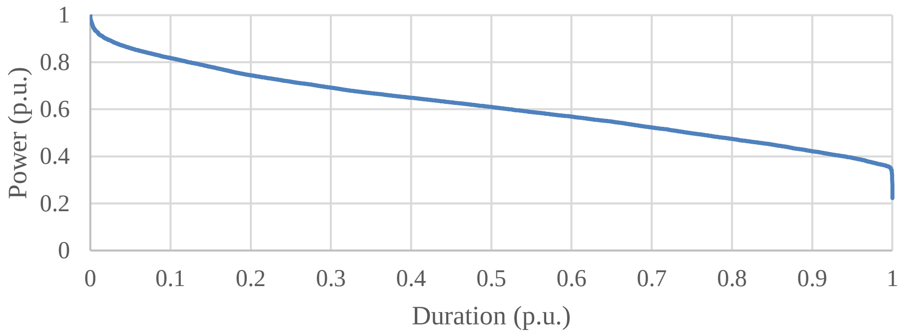


Figure 4. Normalised annual load duration curve

Weighted failure rates observed for the East Fife district circuits (which is wider than the FUSION trial area) are combined by circuit mix and overall failure rate per circuit mix as presented in Table 2. The analysis is based on 587 HV circuits with the total length of 4,864 km and supplying almost 400,000 customers. The average failure rates range from 5.8% for underground circuits to 15.0% of occ./km.year for the MB circuit mix.

Table 2. East Fife district overall circuit parameters

Circuit mix	Mix key	Circuits count	Total circuit length (km)	Total connected customers on circuits	Failure rate (occ./km.year)
OH	80% to 100% OHL	20	641	9,172	11.7%
MC	50% to 80% OHL	78	1,664	65,688	14.2%
MB	20% to 50% OHL	59	766	61,653	15.0%
MA	0% to 20% OHL	71	527	73,261	11.0%
UG	0% OHL	359	1,268	188,065	5.8%
Total		**587**	**4,864**	**397,839**	

Table 3 shows the parameters of the HV feeders relevant for the FUSION trial. Green, orange, and red colours of feeder ID denote feeders containing trial flexibility assets, the first and second-level neighbouring feeders, respectively. No third-level neighbouring feeders are observed. Ten out of 17 HV feeders in the local network fall into one of the above three categories and are therefore relevant for trial data analysis. The HV feeders supply 7,160 customers through 380 distribution transformers. The overall peak demand is 20.2 MW. Total network length is about 200 km, of which 13 km refers to the main overhead (OH) sections, 43 km is main underground (UG), 117 km is lateral OH, and 27 km is lateral UG. Feeders are interconnected through 8 normally open points (NOPs).

3.3. Reference feeder reliability performance

In this section, network reliability performance is first quantified without considering the trialled flexibility resources. Performance is quantified for each of the relevant feeders in terms of expected Customer Minutes Lost (CML) and Expected Energy Not Supplied (EENS). EENS is used as a standard measure of risk when studying contributions to the security of supply.

Feeder 18623 has the highest expected Customer Minutes Lost (CML) as shown in Figure 5a. It is driven by longer repair times, given the length of the feeder, and only one useful NOP that is located close to the start of the feeder, given that a high proportion of the length is classified as lateral.

Table 3. HV feeder characteristics. Green: feeders containing trial flexibility asset, orange: green neighbouring feeders, red: second level green neighbouring feeder.

Site name	Feeder ID	Load points count	Customers count	Peak demand kW	Peak utilisation	Feeder length				Mix	NOPs count
						Main		Lateral			
						OH	UG	OH	UG		
St Andrews Primary	18614	54	1,166	4,687	87.2%	6.37	9.15	10.28	5.63	MC	3
	18615	13	732	1,423	33.8%	0	3.85	0	1.36	UG	1
	18616	12	1,521	2,291	37.6%	0	5.44	0	0.16	UG	1
	18622	7	268	4,719	87.7%	0	5.61	0	0	UG	2
	18623	194	816	2,019	47.6%	3.74	1.57	87.52	8.89	OH	1
	18624	74	1,342	2,059	48.9%	3.18	5.42	18.11	8.82	MC	3
Leuchars Primary	19312	6	298	402	6.6%	0	2.46	0	0.41	UG	1
	19313	7	388	710	11.6%	0	2.16	0.26	1.81	MA	1
	19323	5	130	1,085	26.0%	0	2.96	0.22	0.40	MA	1
	19324	8	499	826	9.9%	0	3.89	0.16	0	MA	2
Total		**380**	**7,160**	**20,221**		**13.29**	**42.51**	**116.56**	**27.49**		**16**

Feeder 18614 has the next highest CML figure. The thermal-driven CML is relatively high compared to other components due to the inability of the neighbouring feeder(s) to support the whole of the unsupplied load as feeder(s) will become overloaded. The next highest CML component for feeder 18614 is repair-driven when the fault must be repaired for the load to be resupplied, i.e., when the load is connected to a lateral or there is no available switchgear to isolate faulty section and load. There is a relatively longer lateral with relatively higher loading which might be backfed in the future when load increases beyond Group Demand A. To reduce thermal- and repair-driven CML, various mitigation measures such as mobile generation could be applied to resupply customers earlier. Nevertheless, this is not considered in the presented analysis. Switching-driven CML is relatively low given that automation is implemented albeit not on all disconnectors.

Feeder 18624 follows a similar pattern as for feeder 18614 but also has a very small voltage-driven CML. CML values for feeders 18622 and 18616 are practically entirely thermal-driven and for feeders 18615, 19313 and 19324 are practically entirely repair-driven.

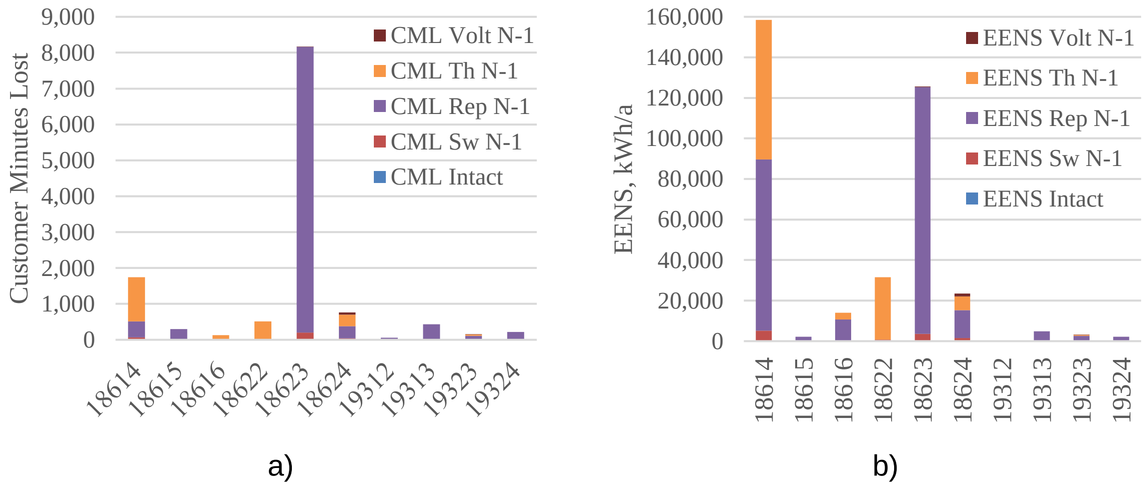


Figure 5. a) Customer minutes lost and b) expected energy not supplied

Expected Energy Not Supplied (EENS), presented in Figure 5b, shows similar trends to CML and, in addition to the outage duration also includes the severity of the outage (in kW of lost load). Given the higher peak loading, feeder 18614 has a higher EENS than feeder 18623.

3.4. Trial data

Flexibility resources in the FUSION trial are available at four distribution sites, as shown in Table 4. There is 291 kW available in Leuchars congestion point, while 638 kW is available in St Andrews congestion point. More specifically, 291 kW is connected in feeder 19324, 85 kW in feeder 18615 and 553 kW in feeder 18614. The overall observed reliability of USEF-based flexibility, quantified as the ratio between delivered and promised energy reduction, is about 73% [12]. For comparison, the BaU reliability is 65% [12].

Table 4. Flexibility locations in FUSION trials

Primary	Feeder	Flexibility ID	Capacity (kW)	Asset flexible rating (kW)	Max runtime (h)
Leuchars	19324	Ener_Portfolio_7	291	291	1
St Andrews	18615	Ener_Portfolio_4_S_Univers	85	85	24
	18614	Ener_Portfolio_6	305	305	1
	18614	238_CHP_University_S	238	238	2
	18614	15_Chiller_Gateway_University_S	80	10	1
Total			**999**	**929**	

The availability and average utilisation prices used in the trial are shown in Table 5 for each aggregator and each congestion point.

Table 5. Availability and average utilisation price used in the trial for each aggregator and congestion point (source: DNV)

Congestion point	Aggregator	Contract availability price (£/kW/hr)	Average utilisation price in trial (£/kWh)
Leuchars primary	Orange Power	13.5	0.47
St Andrew Primary	GridImp	17	0.40
	Orange Power	13.5	0.48

The analysis of the rebound effect is not part of the trial scope. A DNV desktop study[2] provided ranges for rebound energy per technology (EV 40-70%, HP/water heater 71.4%, battery and solar 54-84%, other DSR 50%, Combined Heat and Power (CHP) 0%, and Heating, Ventilation and Air Conditioning (HVAC) 75%).

3.5. Contribution to Security of Supply

The analysis of the contribution to the security of supply consists of two steps. In the first step, peak demand minimisation is carried out for a typical peak day profile and flexibility parameters: available capacity, maximum duration, and load recovery characteristic. The analysis is done at two load levels, at the primary substation and at the feeder level, to show the impact of the scale of flexibility relative to the peak demand. Minimum and maximum contributions to peak demand are quantified for maximum and minimum load recovery, respectively. The contribution to peak reduction obtained from the first step is used in the second step, which analysed the network while taking into account the reliability of delivery of flexibility services. The ELCC approach is applied by quantifying the level of potential peak demand increase in system with flexibility which will provide the same level of risk as with baseline load in system without flexibility.

[2] DNV: Rebound effect analysis slides, 06 September 2022

3.5.1. Peak minimisation

Figure 6 shows the normalised uncontrolled and controlled typical peak day profiles for the Leuchars substation. The uncontrolled peak is 3,354 kW. The controlled profile is obtained by peak minimisation, considering the 291 kW flexible capacity asset that could be split into multiple smaller individual assets that could be utilised independently, each with a maximum flexibility period of 1 hour. The achieved peak reduction is about 156 kW, which provides a contribution to the security of supply of 54% (of flexible capacity) for the lower bound of load recovery of 41%.

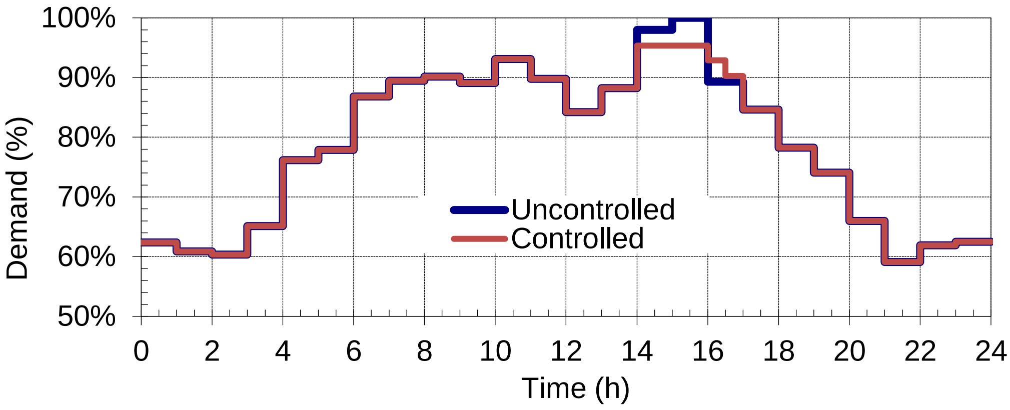


Figure 6. Leuchars normalised uncontrolled and controlled profiles. Control is achieved with flexibility of 291 kW and 1-hour max runtime assuming lower bound load recovery of 41%. Peak reduction is 156 kW.

The St Andrews primary peak is relatively high compared to the available capacity of flexibility assets, and the difference to the second-highest half-hourly demand value is 337 kW, which is greater than flexible asset capacities. Hence, a full 100% contribution is achieved for all assets connected to St Andrews feeders, as shown in Table 6.

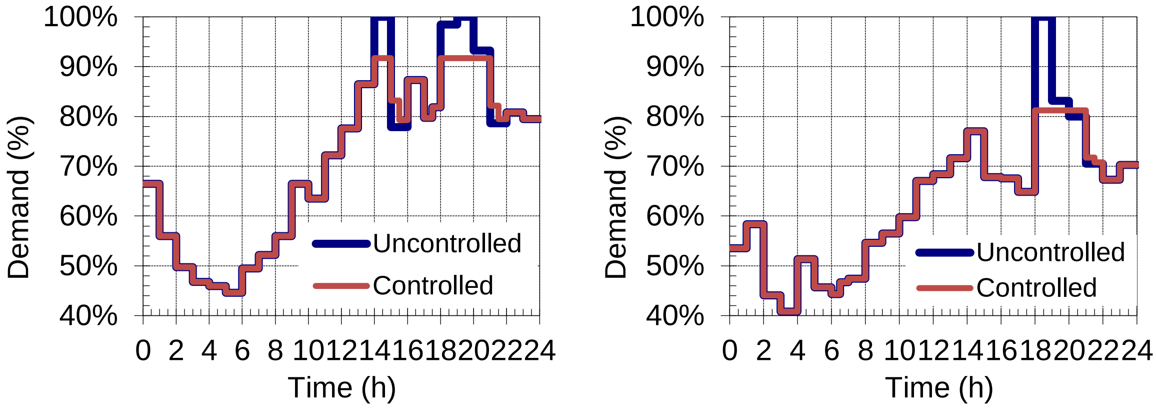
Table 6. Contribution considering primary peak day profiles using continuous approach

Primary	Feeder	Flexibility ID	Capacity (kW)	Max runtime (h)	Contribution	
					Min	Max
Leuchars	19324	Ener_Portfolio_7	291	1	52%	54%
St Andrews	18615	Ener_Portfolio_4	85	24	100%	100%
	18614	Ener_Portfolio_6	305	1	100%	100%
	18614	238_CHP	238	2	100%	100%
	18614	15_Chiller	10	1	100%	100%

Contribution to security of supply from flexibility resources by considering the relevant HV feeder profiles is given in Table 7 considering two approaches: continuous and discrete. Generally, contribution to the feeder security of supply would be lower than for the primary as flexible capacity represents a greater percentage of peak demand. Figure 7 shows uncontrolled and controlled demand profile for feeder 19324, for which flexibility contribution differs depending on the considered day even though the peak demand is the same. Peak reduction is about 71 kW and 162 kW for 7 February and 1 January resulting in the contribution of 25% and 56%, respectively. This shows that it is important to consider multiple days to adequately quantify the contribution of flexibility to security of supply.

Table 7. Contribution considering feeder peak day profiles for continuous and discrete approaches

Primary	Feeder	Flexibility ID	Capacity (kW)	Max runtime (h)	Contribution			
					Continuous		Discrete	
					Min	Max	Min	Max
Leuchars	19324	Ener_Portfolio_7	291	1	22%	25%	0%	9%
St Andrews	18615	Ener_Portfolio_4	85	24	100%	100%	100%	100%
	18614	Ener_Portfolio_6	305	1	77%	82%	43%	52%
	18614	238_CHP	238	2	100%	100%		
	18614	15_Chiller	10	1	100%	100%		



a) 7 February 2021 b) 1 January 2021

Figure 7. Feeder 19324 normalised uncontrolled and controlled profiles. Control is achieved with flexibility of 291 kW and 1-hour max runtime assuming lower bound load recovery of 41% in two different days with the same peak.

The continuous approach to quantifying security contributions assumes that flexible capacity can be divided into an arbitrary number of small independent capacity segments that can be utilised at different times. In the discrete approach on the other hand, the security contribution of flexibility assumes that either all or none of flexible asset capacities can be utilised at a given time. It should be noted that the 85-kW portfolio at St Andrews primary (Ener_Portfolio_4) consists of two assets with sizes of 50 kW and 35 kW. The contribution of discrete assets to security of supply is generally lower than the contribution of multiple assets with the same total flexible capacity.

3.5.2. Network analysis

Figure 8a shows the CML when considering flexibility provision for the USEF-based scenario. A reduction in CML between BaU and USEF scenarios is only observed for feeder 18614, where thermal-driven CML is reduced from the reference case (shown in Figure 5a) by 509 and 543 minutes per customer, respectively. Hence, an additional 34-minute CML reduction per customer is observed in the USEF scenario relative to BaU, as shown in Figure 8b. No reduction is observed in feeders 18615 and 19324 as no thermal-driven CML is observed in these feeders in the counterfactual (no-flexibility) case.

Figure 9a shows the EENS quantified for the USEF-based flexibility scenario. Similarly to the CML results, thermal-driven EENS is reduced by 26,759 and 28,549 kWh/a for feeder 18614 in BaU and USEF scenarios, respectively. USEF therefore provides an additional 1,790 kWh/a reduction in EENS compared to BaU performance (Figure 9b).

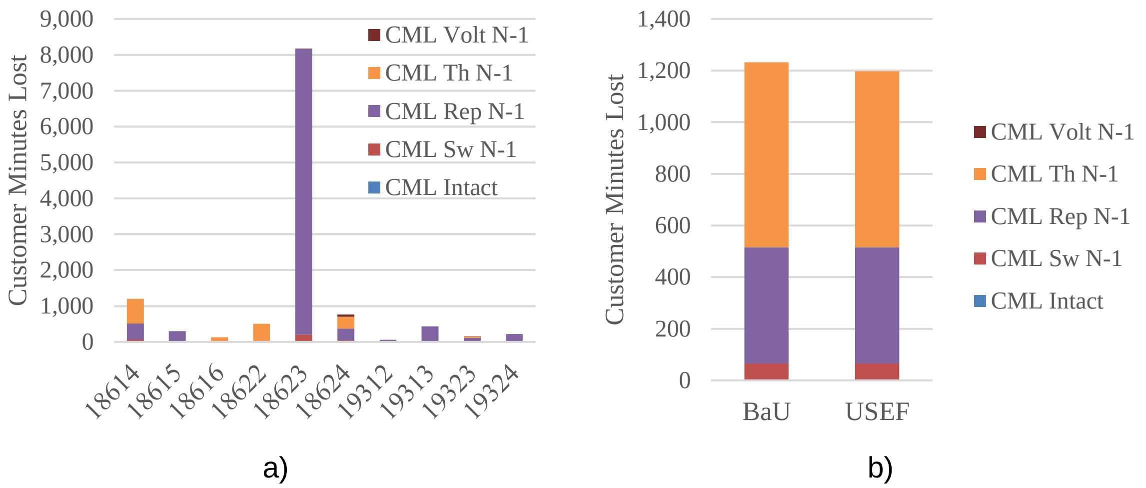


Figure 8. CML for a) USEF-based flexibility and b) difference between BaU- and USEF-based flexibility scenarios for feeder 18614 (the only feeder where difference is observed).

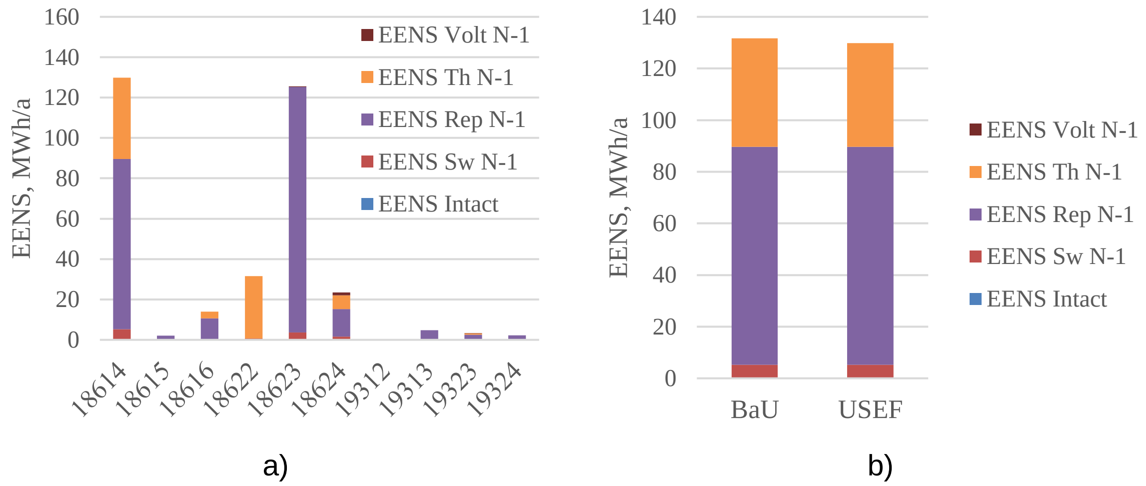
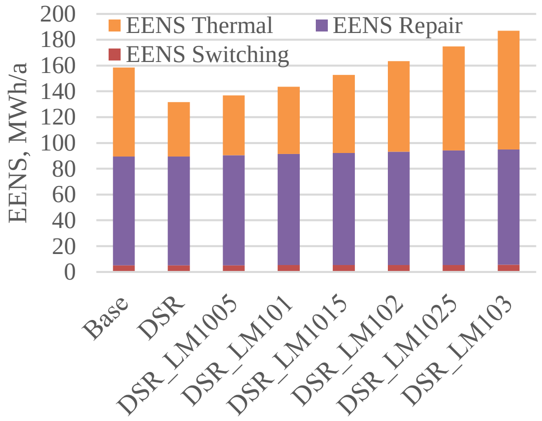
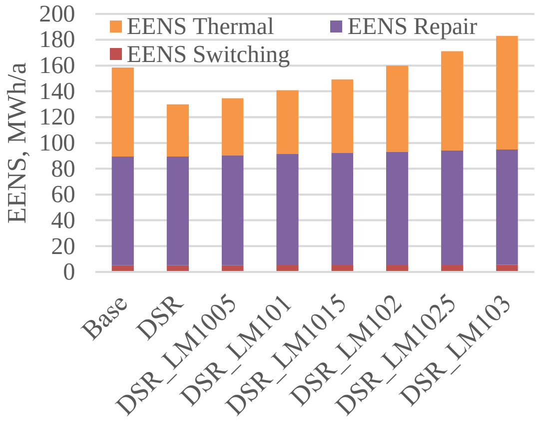


Figure 9. EENS for a) USEF-based flexibility and b) difference between BaU- and USEF-based flexibility scenarios for feeder 18614 (the only feeder where difference is observed).

Figure 10 shows the EENS for feeder 18614 for different flexibility scenarios: a) BaU- and b) USEF-based and across various load growth rates. ELCC of flexibility is quantified as increase of peak demand resulting in the same EENS as without flexibility. For this feeder, a load increase of about 1.6% and 1.8% results in the same EENS as in the counterfactual case for BaU- and USEF-based flexibility, respectively. This corresponds to about 63 and 69 kW, respectively, of demand increase, resulting in contribution of about 11 and 12%, respectively, relative to 553 kW of flexibility connected to feeder 18614. It should be noted that this contribution refers to a single feeder, although other neighbouring feeders could also benefit from this flexibility.



a)



b)

Figure 10. EENS for feeder 18614 for different cases and for a) BaU- and b) USEF-based flexibility. Base is the counterfactual case, DSR case includes flexibility, while DSR_LMnn assumes flexibility as well as load increase denoted by nn (e.g., 1005 denotes 0.5%, 101 denotes 1% and so on up to 103 denoting 3%). Differences between values in charts a) and b) are only in the thermal-driven EENS component, and are around 4-5% of the BaU thermal-driven EENS.

It should be noted that in this analysis of network and trial data, the difference between the BaU- and USEF-based flexibility lies in different availability rates, while the capacity of the flexibility assets is assumed to be the same. When considering the benefits of FUSION at the GB level (Section 4), one of the major drivers for higher value of FUSION is the assumption that FUSION might deliver a significant increase in the volume of the future flexibility in the residential sector.

3.6. Benefit of Flexibility

Based on network data, the total length of overloaded overhead and underground sections is quantified as a function of load increase for feeder 18614. Figure 11 shows the reinforcement cost for feeder 18614 as a function of the load multiplier relative to current value, assuming £110k/km and £30k/km for underground cable installation and reinforcement of overhead lines, respectively.

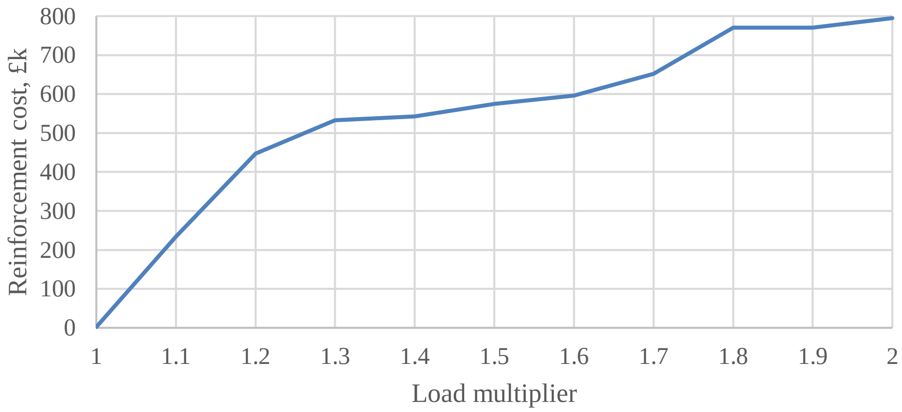


Figure 11. Feeder 18614 reinforcement cost as a function of load increase

Figure 12 shows the peak demand increase in four SP DFES scenarios for the two primary sites. Faster peak demand growth is expected for Leuchars primary with the highest peak demand growth in the Customer Transformation (CT) scenario and the lowest in Leading the Way (LtW) until 2027, and System Transformation (ST) from 2028. For St. Andrews primary the highest peak demand growth is projected in the ST scenario until 2027 and in the CT scenario thereafter, while the lowest is in the LtW scenario. Load increases of 1.6% and 1.8% percent, which flexibility could accommodate, translates to about £37k and £42k, respectively of feeder reinforcement cost that could be deferred for four (for CT) to five (LtW scenario) years, starting from 2022. In later years, the forecasted load increase is higher and feeder reinforcement could be deferred by fewer years (e.g., one to two years), effectively reducing the potential benefit of flexibility.

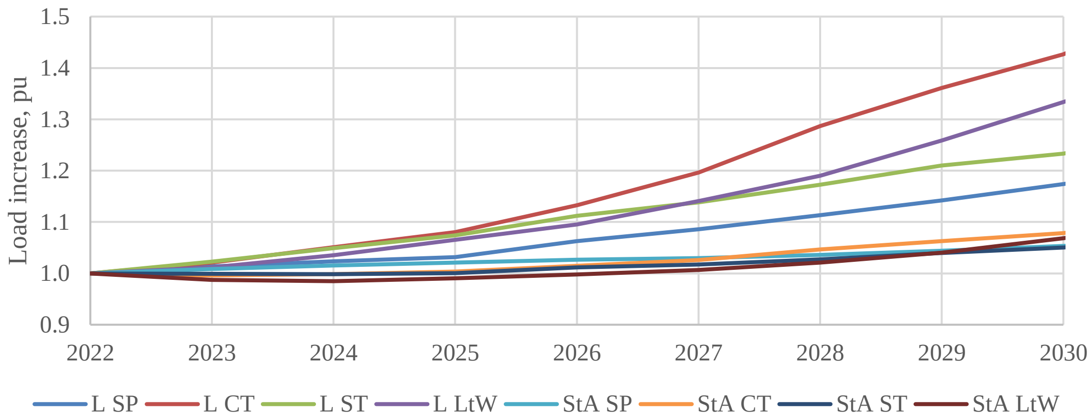


Figure 12. Peak demand (without flexibility) growth for Leuchars (L) and St. Andrews Cross (StA) primaries for four DFES scenarios Steady Progression (SP), Customer Transformation (CT), System Transformation (ST) and Leading the Way (LtW)

Similarly, if the feeder is reinforced, given that its upgrade plans are already in place, the flexibility could be used in later years, but the reinforcement cost increase per load increase is lower and hence reinforcement could only be deferred for a shorter period. The analysis is based on a four-year reinforcement deferral.

The following potential savings are quantified using the CEM tool [13]:

- Value of four-year reinforcement deferral of feeder 18614:
  - Assuming feeder upgrade investment is spread over all four years, the net present value of deferral is £4,539 and £5,135 for BaU- and USEF-based flexibility control, respectively, resulting in additional value of £613 (13.5%) for USEF-based flexibility.
  - Assuming feeder upgrade investment occurs fully in the first year (for clarity, upgrade deferral is still four years), the net present value of deferral is £4,784 and £5,431 for BaU- and USEF-based flexibility control, respectively, resulting in slightly higher additional value of £647 (13.5%) for USEF-based flexibility.
- Value of CML reduction is £647 and £729 for BaU- and USEF-based flexibility control, respectively, resulting in additional value of £82 (12.7%) for USEF-based flexibility.
- Cost of flexibility:
  - Assuming trial-based availability and utilisation prices and post-fault dispatch of flexibility, the cost of flexibility is £17,733 and £15,762 for BaU- and USEF-based flexibility control, respectively.
  - Assuming trial-based availability and utilisation prices and pre-fault dispatch of flexibility of two hours per weekday over two months, the cost of flexibility is £2,192,512 and £1,948,900 for BaU- and USEF-based flexibility control, respectively.
- Breakeven price of flexibility:

- Equivalent pre-fault blended availability price, including utilisation price scaled to availability window, over two-month period for two hours per weekday, is £77/MW/h and £98/MW/h for BaU- and USEF-based flexibility control, respectively, or
- Equivalent pre-fault utilisation price, where critical network outages for feeder happens on average once in 10 years, is £307/MWh and £391/MWh

Availability prices used in the trial are not likely to be representative of future flexibility prices or applicable across other grid areas since FUSION represents an innovation trial and hence the cost of availability will factor in the cost of implementation and enablement of the assets. The actual future availability and utilisation prices of flexibility will be market-dependent. Comparison between the above calculated prices and SPEN weighted-average accepted prices for flexibility[3] is shown in Figure 13. Figure 13a) shows a comparison with the prices of the Secure product, assuming 10% utilisation of flexibility within an availability window, i.e., the blended utilisation price is 10% of the accepted utilisation price. Prices are weighted by volume of accepted flexible capacity. The observed breakeven prices of flexibility are similar to the average prices of the Secure product in earlier years (2023/24 and 2024/25), and to the prices of the Sustain product in SPEN procurements from 2025 onwards.

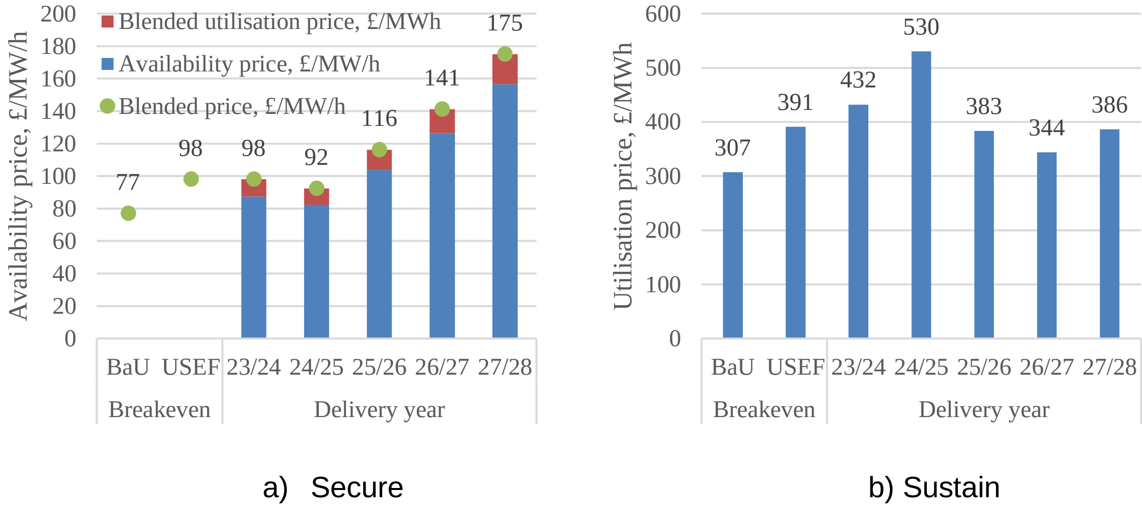


Figure 13. Comparison between the calculated breakeven and SPEN accepted flexibility prices for a) secure and b) sustain products

There is no benefit of flexibility for the HV trial-network in other two feeders, where flexibility assets are connected to, given that no thermal-driven EENS is observed at present. Flexibility would become beneficial in the future as more load connects to the feeders.

As mentioned earlier, the only assumed difference between BaU- and USEF-based flexibility scenarios for the trial area is in different availability rates of delivering flexible services, while the volume of flexible capacity and the rebound effect are assumed to be the same. Considering all installed capacity, the potential additional benefit of USEF-based flexibility, including both network upgrade deferral and reduction in CML, is found to be between £0.75-0.78/kW of considered flexibility in the trial area across the total flexible capacity of 929 kW. Note that this represents the flexible capacity installed in all three feeders, even though no present-day benefit is observed in two of those feeders, as shown in Table 4. It should also be

[3] SPEN 2022 Procurement Data spreadsheet: https://www.flexiblepower.co.uk/downloads/1092 (direct link) or select Procurement Data link under section 2022 Procurement Reports.

noted that the additional benefit could be lower in later years when the forecasted rate of peak demand increase will be greater year-on-year and the cost of network upgrade is lower.

If flexibility is costed using trial flexibility unit prices, there would be no net benefit, including the case of perfect knowledge as to when a fault would occur (i.e., post-fault application). Flexibility might need to be utilised in a pre-fault manner, in which case the cost of flexibility (using the trial prices) would be significantly higher, about £2m, while the potential benefit of flexibility due to network deferral and CML reduction would only be about £5-6k.

The analysis so far has focused on the FUSION trial area and additional benefit derived from difference in observed reliability in USEF trials compared to the average BaU reliability observed in other projects for the same type of flexibility assets. In contrast, the analysis in Section 4.2.4 also considers benefits associated with unlocking additional flexible capacity (which was not the focus of FUSION trials) in future years, showing very significant GB-wide benefits of FUSION flexibility.

3.7. Conclusion

Contribution of flexibility to the security of supply of local distribution network is driven by:

- Size of flexibility compared to peak demand: for higher volume of flexibility its relative security contribution generally reduces, as the width of the relevant peak demand window becomes greater. For example, for the St Andrews location the maximum contribution of the 305 kW flexibility resource was 82%, while the contribution of the 10 kW resource was 100%, as shown in Table 7.
- Number of flexibility assets: contribution of a smaller number of flexibility assets is lower than the contribution of more flexibility asset with the same total available flexible capacity. For example, the maximum contribution of 291 kW of flexibility shown in Table 7 is lower when there is only one flexibility asset assumed (9%) compared to 25% when multiple assets are assumed.
- Location of flexibility in the network: flexibility assets located closer to the NOP location rather than towards the beginning of a feeder could provide a greater contribution. This effect was not considered in this report.
- Level of congestion during an outage: the higher the congestion during an outage, the lower the security contribution, as the relevant peak demand window becomes wider and longer, in a similar fashion as for the size of flexibility mentioned above i.e., more flexible capacity is needed.
- Shape of the profile: in general terms, the security contribution of flexibility where the demand profile is flat would be lower compared to the situation where the profile is peakier, for similar reasons as for the size of flexibility discussed above. This is illustrated in Figure 7 where the contribution is observed to be greater in the case of a narrower peak (56%) as opposed to 25% when the peak is wider.

In two out of three HV feeders where FUSION trial flexibility assets are connected there is no network congestion observed. Potential additional savings of USEF-based flexibility that could be achieved on feeder 18614, for which network congestion is observed, are about £695-728 (or about 13%) (from both network deferral and CML reduction), when quantified relative to the savings from BaU-based flexibility. Additional savings could also be achieved because slightly less flexible capacity needs to be deployed for the same effect due to the higher assumed availability of USEF-based flexibility, although this would very much depend on the availability and utilization prices (there appears to be no net benefit in this respect if the trial prices are used, as those prices are similar to the Value of Lost Load).

Another potential benefit of flexibility could be reflected in enabling earlier demand/generation connections relative to the counterfactual connection schedules. Nevertheless, the assessment of these benefits is not within the scope of this project.

4. Establishing Whole-System Benefits of FUSION concept in low-carbon GB electricity system

The main objective of this section is to quantify whole-system benefits of rolling out the FUSION concept nationwide to unlock distributed flexibility resources that would otherwise have a very difficult route to market.

More specifically, the objectives of the section are to:

- Assess the whole-energy system cost implications of large-scale deployment of FUSION concept and contrast them to scenarios without FUSION;
- Evaluate the benefits of FUSION concept in the context of GB electricity sector decarbonisation, and break them down into categories and asset types;
- Quantify the impact of energy system pathways on the benefits of FUSION for electricity system decarbonisation.

4.1. Approach to assessing system impacts of FUSION

This section summarises the approach adopted to quantify the whole-system benefits of a large-scale rollout of the FUSION concept. The section also describes the scenarios and key assumptions used in the whole-system analysis.

4.1.1. Quantifying whole-system benefits of distributed flexible technologies

Capturing the interactions across different time scales and across different asset types is essential for the analysis of future low-carbon electricity systems that include flexible technologies such as energy storage and demand side response. To capture trade-offs between different flexible technologies, it is critical that they are all modelled in a single integrated modelling framework. To meet this requirement, the analytical team at Imperial has developed **Whole-electricity System Investment Model (WeSIM)**, a comprehensive system analysis model that is able to simultaneously balance long-term investment decisions against short-term operation decisions, across generation, transmission and distribution systems, in an integrated fashion.

WeSIM determines optimal decisions for investing into generation, network and/or storage capacity (both in terms of volume and location), to satisfy the real-time supply-demand balance in an economically optimal way, while at the same time ensuring efficient levels of security of supply. An advantage of WeSIM over most traditional models is that it can simultaneously consider system operation decisions and capacity additions to the system, with the ability to quantify trade-offs of using alternative mitigation measures, such as DSR and storage, for real-time balancing and transmission and distribution network and/or generation reinforcement management. A prominent feature of the model is the ability to capture and quantify the necessary investments in distribution networks to meet demand growth and/or distributed generation uptake, based on the concept of statistically representative distribution networks. These statistical archetypes used in the model have been calibrated to actual GB distribution networks to ensure a highly accurate representation of network length, number of transformers and network reinforcement cost.

Analysing future electricity energy at sufficient temporal and spatial granularity is essential for assessing the cost-effectiveness of alternative decarbonisation pathways. In this context, WeSIM based modelling has clearly demonstrated that in order to quantify system operation and investment cost and the carbon performance, quantitative models need to simultaneously consider second-by-second supply-demand balancing issues as well as multi-year investment (e.g. reduced system inertia may trigger investment in flexible technologies). Furthermore, electricity system decarbonisation will also need to adequately consider the synergies and conflicts between local/district level and national (or trans-national) level infrastructure requirements, which is another key feature of WeSIM.

WeSIM carries out an integrated optimisation of electricity system investment and operation and considers two different time horizons: (i) short-term operation with a typical resolution of one hour or half an hour (while also taking into account frequency regulation and short-term reserve requirements), which is coupled with (ii) long-term investment i.e. planning decisions with the time horizon of typically one year (the time horizons can be adjusted if needed). All annual investment decisions and 8,760 hourly operation decisions are determined simultaneously to achieve an overall optimality of the solution. Key features and constraints considered in WeSIM include: a) power balance, b) reserve and response requirements, c) generator operating limits, d) demand-side response capability; e) distribution network investment, f) carbon emission constraints, g) constraints on electricity imports and exports, and h) security constraints.

4.1.2. Scenarios and key assumptions

This section lays out the key assumptions made in quantitative system modelling, including the key features of system scenarios and the assumptions on the volume of distributed flexibility in the GB system unlocked through the deployment of FUSION.

4.1.3. Electricity system scenarios

The electricity system scenarios used in this study are based on the System Transformation (ST) and Consumer Transformation (CT) scenarios from the 2022 version of National Grid's Future Energy Scenarios (FES)[4]. The analysis presented here focuses on two snapshot years: 2035 and 2050.

Key features of the two system scenarios are as follows:

- **System Transformation**
  - High share of hydrogen for heating
  - Consumers less inclined to change behaviour
  - Lower energy efficiency
  - Supply side flexibility
- **Consumer Transformation**
  - High share of electrified heating
  - Consumers willing to change behaviour
  - High energy efficiency
  - Demand side flexibility

ST and CT scenarios were chosen because of the difference in the assumptions as to how the bulk of low-carbon heat is delivered in the residential and commercial sectors, with ST relying much more on hydrogen, and CT almost exclusively on electricity.[5] As explained later, residential flexibility is assumed to be the main differentiator for the benefits of FUSION,

[4] National Grid ESO, "Future Energy Scenarios", https://www.nationalgrideso.com/future-energy/future-energy-scenarios. FES outline four different credible pathways for the future energy system until 2050, three of which meet the UK-wide target of net-zero GHG emissions.

[5] The third scenario that meets the net-zero target for the UK energy system, Leading the Way, assumes the decarbonised heat is delivered by a mixture of electricity and hydrogen, and can therefore be expected to lead to system benefits of FUSION that are between those quantified for the ST and CT scenarios.

therefore the choice of these two scenarios can be expected to identify the range of system benefits of FUSION for the future system. Electrification of transport, which is another key potential source of residential flexibility, was assumed to develop at a similar pace across different scenarios laid out in FES, with the majority of light vehicle fleets transitioning to battery electric vehicles.

Both scenarios included a high volume of renewable generation capacity. In ST the assumed capacity of wind in 2050 was 132 GW and the capacity of solar PV 57 GW, whereas in CT the respective figures were 158 GW and 79 GW. For reference, the current installed capacities of wind and solar PV in the UK are 27.9 GW and 14.2 GW, respectively.

In all case studies it is allowed in the model to invest in additional generation and energy storage capacity if needed to meet the demand, fulfil security criteria or achieve the carbon target. All cases assumed that the system needs to meet the net-negative carbon emission targets consistent with ST and CT scenarios from FES, which effectively required that the model invests in carbon offsetting technologies such as Bioenergy with Carbon Capture and Storage (BECCS).

When modelling the household heat requirement at the GB level, the model assumed normal temperature variations across the year, apart from a three-day cold weather spell occurring in January. This was introduced to ensure that the electricity infrastructure can reliably supply demand even in the extreme case of a 1-in-20 cold winter.

4.1.4. Assumptions on volume of flexibility with and without FUSION

Assumptions on large-scale flexibility, including the uptake of large-scale industrial DSR and the lower bound on the volume of grid-scale energy storage and interconnectors were kept in line with the assumptions laid out in the ST and CT scenarios in FES. Assumptions on distributed flexibility on the other hand, were modified to reflect the impact of rolling out the FUSION concept, i.e., implementing USEF to unlock small-scale residential and commercial DSR.

Discussions with FUSION project partners indicated that one of the potential benefits of USEF (i.e., FUSION) over BaU, in addition to improving the reliability of delivering flexible services, would be to unlock additional residential flexibility resources that would otherwise remain unutilised. This primarily refers to customer-side assets such as smart electric vehicles, smart heating system and smart appliances, which currently do not participate in DNO-level or national flexibility markets as they are considered as non-firm (i.e., non- deterministic) flexibility providers. Therefore, in the whole-system assessment presented in this section it was assumed that FUSION would enable an increased volume of flexibility from the residential sector to become available in the market.

The assumptions on the volume of flexibility available in the residential sector through electrified transport, heating and smart appliances in the FUSION case studies were adopted from the actual DSR assumptions specified in FES for the ST and CT scenarios, implying that this level of flexibility has (at least partially) been enabled through concepts such as FUSION. As an illustration of the DSR capability expressed in terms of the fraction of peak demand that can be shifted in 2050, the EV demand flexibility allowed for shifting of 27% (ST scenario) and 40% (CT scenario) of peak demand, while for the electrified heating demand the corresponding figures were 25% and 50%.

In the “no FUSION” case studies on the other hand, the DSR available from distributed residential resources was scaled down to reflect the situation where the bulk of distributed flexible resource remains unutilised due to lack of suitable market framework. The flexibility of smart appliances was not considered in these case studies, while the flexibility of EV demand

and heating demand was reduced to 10% and 5%, respectively. These assumptions were made based on expert judgement for the Imperial team, reflecting the view that it is more realistic to assume a low rather than zero level of flexibility for EV and heat demand in the BaU scenarios, as it can be expected that some level of flexibility would materialise even without the deployment of the FUSION concept.

4.2. Quantitative modelling results

In this section the results of quantitative energy system modelling, focusing on the impact of FUSION on: i) total system cost, ii) cost-efficient generation capacity mix, and iii) net peak demand are discussed.

4.2.1. Impact on total system cost

Due to the whole-system nature of the whole-system modelling approach, the resulting effects on total system cost are disaggregated into multiple components of cost savings, distinguishing between generation investment cost (both low-carbon and conventional), storage investment cost, operating cost and distribution network investment cost. Distribution network reinforcement cost has been quantified using the LRE model. The cost of enabling DSR is not included in cost figures presented in this section (this is studied in more detail in Section 5). Therefore, any whole-system benefits quantified in this section represent gross system benefits of FUSION.

The highest proportion of total system cost is associated with investments in low-carbon generation, with sizeable components associated with storage CAPEX, generation OPEX, interconnection CAPEX and distribution network reinforcement cost. The overall system cost increases with time as well as between ST and CT scenarios, primarily driven by the scaling up of electrified heat and transport demand. To provide insights into the key drivers for savings in system costs across different system scenarios, Figure 14 shows the reduction in total system cost enabled by FUSION concept for each scenario and time horizon. This reduction is quantified as the difference in total system cost between the scenario with the FUSION concept implemented and the corresponding scenario without the additional flexibility.

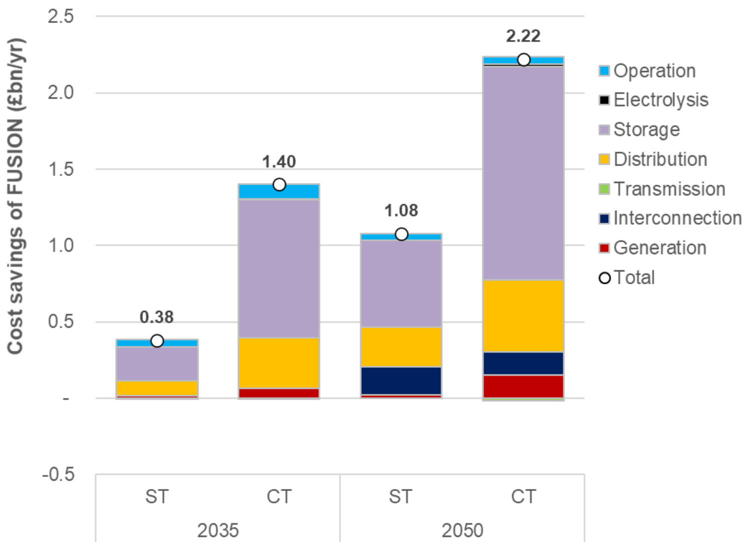


Figure 14. Changes in total system cost across driven by FUSION in various scenarios

The results show that the system benefits of FUSION materialise in various system segments, including:

- Reducing the requirements for distribution network reinforcement that would otherwise be required to accommodate high demand peaks associated with electrified transport and heating;
- Reducing the requirement for peak supply capacity (storage and generation) due to the ability of FUSION-enabled distributed flexibility to shift electricity demand from peak to off-peak periods;
- Reducing the operating cost (OPEX) of thermal generation, mostly unabated gas CCGT generation and BECCS;
- Reducing the requirement for other means of flexibility such as interconnectors.

System benefits of FUSION are observed to vary in magnitude depending on the chosen scenario and time horizon. Cost savings delivered by FUSION are higher in the CT than in the ST scenario and increase significantly between 2035 and 2050. This follows from the higher volume of electrified transport and heating demand in the CT scenario, and this is where FUSION is assumed to unlock local flexibility.

In the ST scenario the benefits of FUSION were found to more than double between 2035 and 2050, from £0.38bn/yr to £1.08bn/yr. In the CT scenario on the other hand, the value reaches £1.4bn/yr already in 2035, which is in line with faster electrification of heat and transport in this scenario, and further increases to £2.22bn/yr in 2050.

4.2.2. Impact on system generation capacity mix

Figure 15 illustrates how the uptake of FUSION affects the cost-optimal mix of generation and storage technologies. The main benefit of FUSION is in avoiding the installation of significant volumes of battery storage capacity, resulting from the ability of FUSION-enabled flexibility to shift demand and therefore substantially reduce net peak demand on the system. In 2050 scenarios there is also some reduction in hydrogen OCGT capacity, although the scale of this is far smaller than the displaced battery storage capacity.

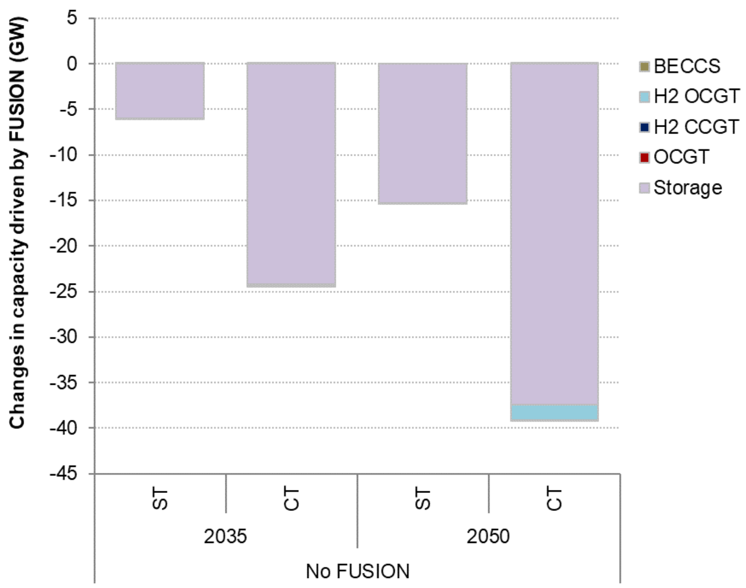


Figure 15. Changes in generation and storage mix driven by FUSION across various scenarios

The volume of displaced peaking supply capacity from storage and generation is driven by the volume of flexible demand unlocked by FUSION in each scenario. Displaced volumes increase between 2035 and 2050 and are much higher in the CT than ST scenario, reaching almost 40 GW of displaced peaking capacity in 2050 for the CT scenario.

4.2.3. Impact on net peak demand

Previous studies by Imperial demonstrated that heat and transport electrification could increase the total cumulative expenditure on distribution networks by up to £50bn by 2035 (or £1.8 billion per year in annualised terms). Utilising localised flexibility through FUSION could significantly mitigate the impact of electrification of heat and transport on peak demand levels and the resulting needs for reinforcing distribution network and peak generation capacity. Figure 16 quantifies the variations in peak demand levels for various scenarios and time horizons, with and without FUSION.

Three peak demand levels are shown:

1. "Pre-DSR": system peak demand before accounting for any DSR or storage actions;

2. "Post-DSR": accounting for DSR actions only (this also includes the impact of demand-side flexibility enabled by FUSION);

3. "Net of BESS & Solar PV": provides an indication of the actual net loading of the distribution grid after accounting for use of DSR and battery storage plus accounting for on-site generation by solar PV (although the energy production of solar PV is essentially zero at the time of winter peak demand).

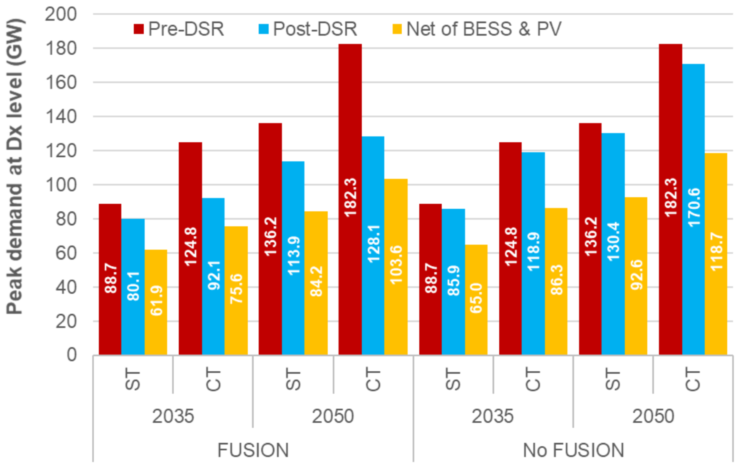


Figure 16. Impact of FUSION on net system peak demand across different scenarios

Driven by the rapidly increasing volume of electrified heating and transport, the system peak demand increases quite significantly between 2035 and 2050 in all case studies. Peak demand is also much higher in the CT than in the ST scenario, mainly due to higher penetration of electrified heating. Unmanaged (pre-DSR) peak demand levels can exceed 180 GW in 2050, which represents a more than threefold increase compared to today's levels.

The flexibility facilitated through FUSION is found to have a very significant effect on net peak demand. For instance, in 2050 the net peak loading of the distribution grid reduces from 93 GW (ST) and 119 GW (CT) in the no-FUSION cases to 84 GW and 104 GW, respectively. As discussed earlier, this has direct implications on the required peaking generation capacity and network reinforcement and can deliver substantial cost savings as a result.

4.2.4. System-wide impact on distribution networks

In this section, the additional potential benefit of USEF-based flexibility, when compared to BaU-based flexibility, is evaluated for two future time horizons (2035 and 2050) over different types of distribution networks and conditions that might exist in the future GB system. As mentioned earlier in this section, the primary benefit of USEF-based flexibility scenario is assumed to be the integration of a higher volume of flexible assets from the residential sector.

A set of 23 *representative networks* has been generated and mapped onto the GB DNOs electricity distribution areas. For the Scottish Power Distribution (SPD) area it was found that eight of the 23 representative networks provide a statistically highly accurate representation of the entire SPD licence area, when observed across a wide range of network parameters, as shown in Table 8.

Table 8. Mapping of representative networks into SPD electricity distribution region

SPD		Actual	Representative	Difference
Customers (total)		2,140,008	2,140,008	0.00%
Domestic unrestricted		1,647,412	1,647,412	0.00%
Domestic Economy 7		343,140	343,140	0.00%
Small non-domestic		130,634	130,634	0.00%
Medium non-domestic		13,678	13,678	0.00%
Large non-domestic		5,144	5,144	0.00%
LV	Overhead (km)	4,402	4,402	0.00%
	Underground (km)	26,822	26,822	0.00%
DT	PMT	25,351	25,351	0.00%
	GMT	16,991	16,991	0.00%
HV	Overhead (km)	14,122	14,122	0.00%
	Underground (km)	12,564	12,564	0.00%

Representative networks are analysed across different scenarios using Imperial's Load Related Expenditure (LRE) model, which determines the volume and cost of network elements (transformers, cables and lines) that need to be upgraded to accommodate a given level of demand. The key outputs of distribution network case studies for each scenario are:

- Evolution of network reinforcement, both in terms of the number of reinforced elements and their cost
- Breakdown of network reinforcement across voltage levels

The key learning points are derived from comparing each scenario with the counterfactual, providing an estimate of the potential benefit of USEF-based flexibility implementation.

As explained earlier, two system scenarios are considered, based on Future Energy Scenarios (FES), Customer Transformation (CT) and System Transformation (ST). Annual profiles obtained from the whole system analysis using the WeSIM model are used to identify the change of baseline peak demand, change of contribution to peak from Electric Vehicles charging (EV), Heat Pumps (HP) and PhotoVoltaics (PV), both in terms of diversified peak and coincidence factor.

It has to be noted that the savings quantified using the LRE model and representative network approach are cumulative rather than annualised, unlike the savings quantified in the WeSIM model and presented in Figure 14. Also, savings quantified using the LRE model are obtained following the strategic rather than incremental investment paradigm (which is implemented in WeSIM), meaning that once a network element is upgraded, it is not replaced by the first larger component but rather with a component that would be sufficient to accommodate any plausible future load increase. Therefore, the results in this section cannot be easily compared with those presented in Section 4.2.1.

Figure 17 shows the difference in GB reinforcement cost in BaU and USEF-based flexibility cases for the two scenarios in 2035 and 2050. The results suggest that GB savings are greater in ST than in CT scenario. Also, in the medium term the savings tend to be higher, suggesting that more network reinforcement could be deferred than in the long term, when demand increase due to heat and transport electrification would me so high to require reinforcement even in the presence of flexibility. In the ST scenario in 2050 the savings are more than double compared to the CT scenario. The highest proportion of savings are in deferring the HV network upgrades. The assumed asset upgrade unit costs are taken from the P2 review report [14].

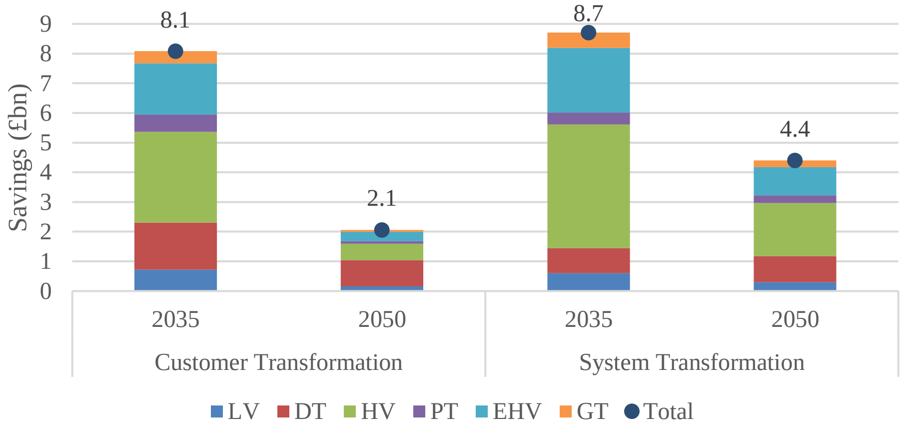


Figure 17. Difference between GB network reinforcement cost of BaU and USEF-based flexibility for two scenarios and two future years. LV: low voltage (network), DT: distribution transformers, HV: high voltage network, PT: primary transformers, EHV: extra high voltage, including 132 kV where relevant, circuits, and GT: grid transformers.

Figure 18 shows the breakdown of savings per rurality. A different trend could be seen for the ST scenario in Urban networks, where network deferral increases in the long-term future.

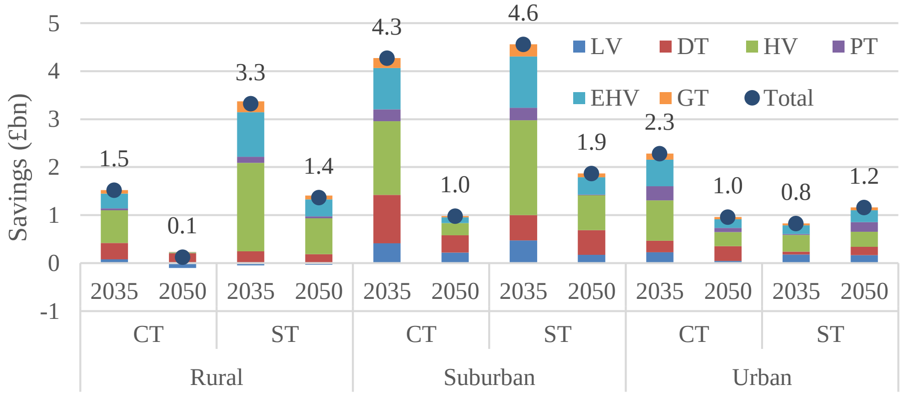


Figure 18. Breakdown of difference between GB network reinforcement cost per rurality of BaU and USEF-based flexibility for two scenarios and two future years. LV: low voltage (network), DT: distribution transformers, HV: high voltage network, PT: primary transformers, EHV: extra high voltage, including 132 kV where relevant, circuits, and GT: grid transformers.

Figure 19 shows the savings calculated per connected customer. The highest observed savings are in the ST scenario in 2035, totalling almost £1.1k/customer.

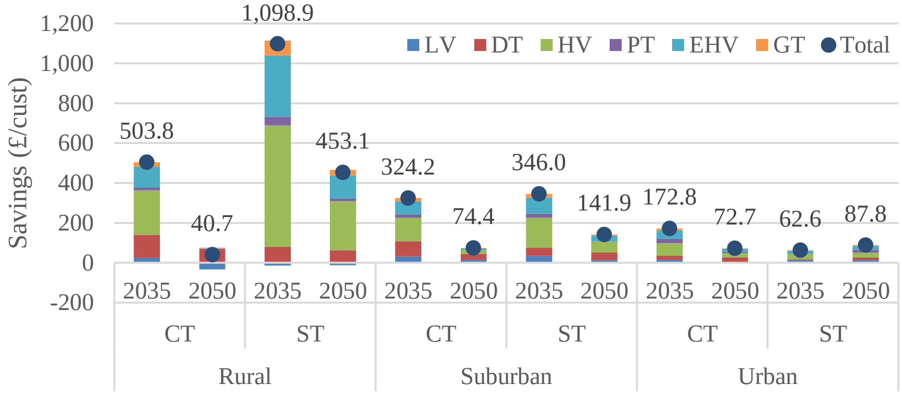


Figure 19. Savings per customer

In summary, potential additional GB distribution network reinforcement deferral in 2035 is between £8.1-8.7bn for CT and ST scenarios, respectively for USEF- compared to BaU-based flexibility. In 2050 this reduces to between £2.1-4.4bn. The main deferral is of investment in HV network except in CT 2050 where deferral of investment in distribution transformers is dominant. Majority of those savings are expected in suburban networks followed by urban networks (for CT scenario) or rural networks (for ST scenario). While observed savings are greater in 2035 than in 2050 for ST scenario, in urban areas the savings are greater in 2050. Savings per customer are greater in rural areas and reach about £1.1k/customer in the ST scenario in 2035 while the smallest savings are also observed in rural areas but for the CT scenario in 2050, at about £41/customer.

4.3. Conclusions

Quantitative modelling assessed the whole-energy system implications of large-scale deployment of FUSION concept in the context of GB electricity sector decarbonisation, specifically evaluating the benefits of FUSION concept and its ability to unlock distributed flexibility resources in the residential sector.

Key findings from the whole-energy system modelling include:

- Deployment of FUSION can deliver cost savings that materialise in various system segments, including reduced requirements for distribution network reinforcement, reduced requirement for peaking capacity, and reduced requirement for other means of flexibility such as interconnectors or hydrogen production.
- These savings are driven by the ability of FUSION to utilise more localised flexibility in the residential sector to shift electricity demand from peak to off-peak periods as well as follow the output of variable renewables.
- System benefits vary in magnitude depending on the scenario and time horizon, with higher benefits in the Consumer Transformation than in the System Transformation scenario, and a significant increase between 2035 and 2050. This is driven by the increasing volume of electrified transport and heating demand, which results in higher absolute level of flexibility unlocked in these sectors also through FUSION deployment.
- In the ST scenario the benefits of FUSION were found to more than double between 2035 and 2050, from £0.38bn/yr to £1.08bn/yr. In the CT scenario the value reaches £1.40bn/yr already in 2035, due to faster electrification of heat and transport, increasing further to £2.22bn/yr in 2050.

- FUSION can help to avoid installing a significant amount of peak supply capacity due to reduced net peak demand on the system. Most of displaced peaking capacity in the study was battery storage capacity, although in general terms FUSION could also displace zero-carbon peak generation capacity such as hydrogen-fuelled OCGTs. Displaced capacity increases between 2035 and 2050 and is higher in the CT than ST scenario, reaching up to 40 GW.

- The flexibility unlocked through FUSION could have a very significant effect on net peak demand, so that in 2050 the net peak loading of the distribution grid reduces from 93 GW (ST) and 119 GW (CT) in the no-FUSION cases to 84 GW and 104 GW, respectively. This has direct positive implications on the required peak supply capacity (such as battery storage or peak generation) and distribution network reinforcement, potentially resulting in substantial cost savings.

- When quantifying GB-wide implications of FUSION deployment using statistically representative distribution networks, based on the outputs from the whole-system model, the benefit of FUSION for GB distribution network reinforcement deferral in 2035 is estimated at £8.1-8.7bn, while in 2050 this reduces to between £2.1-4.4bn. Highest savings are observed in suburban networks followed by urban and rural networks.

5. Business Case Analysis: Cost-benefit analysis of FUSION concept

This section discusses the cost-benefit analysis (CBA) of the FUSION concept from the energy system point of view. The CBA builds on the results of gross economic system benefits established in Section 4 and uses this information to evaluate the net benefits of FUSION concept in two fundamental ways:

- Quantify annual net system benefits as difference between gross system benefits from Section 4 and the cost of implementing FUSION.
- Estimate the Net Present Value (NPV) for the future trajectory of whole-system benefits and costs of FUSION.

In both approaches the estimated cost of implementing the FUSION concept across the DNO flexibility markets in the UK as well as the estimated cost of enabling residential DSR is deducted from gross system benefits to establish the net system benefit of FUSION.

There are few robust estimates of the residential DSR enablement cost in the public domain. This can be attributed to a number of factors, including the early stage of technology deployment (mostly focused on trials), fundamental heterogeneity of various types of flexible residential demand (e.g., electric vehicles, heat pumps or smart appliances), lack of understanding of customers' willingness to engage in future DSR schemes and absence of established business models. To account for this significant uncertainty around the future cost of implementing residential DSR, the last part of this section also quantifies gross system benefits per unit of flexible DSR energy and per unit of flexible DSR capacity in order to establish an upper limit for the acceptable cost of DSR enablement as part of implementing FUSION.

5.1. Assumptions for cost of implementing FUSION and cost of enabling residential DSR

The cost of implementing FUSION (i.e., the USEF framework) is estimated based on inputs received from DNV GL and SPEN. It is assumed that the incremental cost to implement USEF at the level of an aggregator is £30,000 per aggregator. Due to the need to update their flexibility trading platforms, it is also assumed that each DNO company would incur a one-off cost of £87,000 that would be additional with respect to their standard BaU solutions or platforms for local flexibility trading.

It is further estimated at the high level that there will be 10 aggregators connecting to each of the 6 local flexibility markets managed by the 6 DNO companies, implies a total of 60 aggregators and 6 DNOs and the resulting FUSION implementation cost of around £2.3m. Given that the period for NPV calculation spanned three decades, it was further assumed that the FUSION setup cost would be incurred every 10 years as the result of the need to periodically update the software and hardware components of the system. Nevertheless, it is acknowledged that the uncertainties associated with these cost estimates are very significant and therefore they should only be used as indicative values.

Cost of enabling residential DSR was estimated based on a recent report[6] by Element Energy for the Greater London Authority, studying the findings from the Home Response project that trialled domestic DSR solutions in London. The two use cases investigated in the trial included

[6] Element Energy, "Home Response: Domestic Demand Side Response Insights Report", Greater London Authority, March 2022. https://www.london.gov.uk/sites/default/files/hr_-_insights_report_-_final.pdf

i) household battery installations coupled with existing solar PV installations, and ii) smart controls and monitoring equipment for existing electrically heated hot water storage tanks. Although the trials did not include electric vehicles, heat pumps or smart appliances, the costs associated with customer acquisition and recruitment and monitoring and dispatch (i.e., the cost components not including purchase and installation of physical equipment) were fairly robust across the two applications and therefore they were used as basis for estimating the cost of enabling residential DSR.

According to the report, the low end of the one-off cost of customer acquisition and recruitment for smart water heaters was estimated at £94 per consumer, while the annual operating cost required for monitoring and dispatch was estimated at £40 per customer. Given the relatively small size of the trial and the early stage of the technology and contractual arrangements, the low-cost scenario was considered the most relevant for estimating the cost of future large-scale rollout of residential DSR. Furthermore, when looking towards the 2035-2050 horizon, it was assumed that with economies of scale and technology learning these costs would reduce by 20% compared to the current values in 2035, and by 30% in 2050.

The number of flexible customers enabled through FUSION was estimated from the FES data for the two scenarios and time horizons considered:

- System Transformation: 3.36m in 2035, 6.65m in 2050
- Consumer Transformation: 7.82m in 2035, 13.41m in 2050

5.2. Net system benefits of FUSION

Table 9 compares the annualised gross whole-system benefits estimated in Section 4 to the estimated cost of enabling FUSION and rolling out residential DSR, allowing for an estimate of the net whole-system benefits of FUSION.

Table 9. Gross and net annualised whole-system benefits of FUSION

	ST		*CT*	
Costs/benefits (£m/yr)	*2035*	*2050*	*2035*	*2050*
Gross system benefits	380	1,080	1,401	2,221
Implementation/enablement cost	164	644	894	1,567
Net system benefits	**216**	**436**	**507**	**654**

The annual net system benefits of FUSION are found to be positive across all scenarios and time horizons. The cost of implementation and enablement associated with FUSION offsets between 40% and 70% of gross system benefits across various scenarios. Nevertheless, there is still a distinct positive system value driven by deploying FUSION, ranging from £216m/yr in the ST scenario in 2035 to £654m/yr in the CT scenario in 2050.

5.3. Net Present Value of FUSION

The NPV of the FUSION concept is estimated for a 30-year period between 2022 and 2052 based on projected future annual benefits obtained from interpolating WeSIM results obtained for 2035 and 2050. These benefits are interpolated between today and 2052, starting from zero in 2022 and increasing linearly to reach annual values quantified for 2035 and 2050, staying constant beyond 2050. The discounted cost of implementing FUSION and enabling residential DSR is subtracted from discounted system benefits to estimate the NPV of the concept. All costs and benefits are discounted to year 2022 using a discount rate of 5%.

The results of the NPV estimates for the FUSION concept across the two system scenarios used in this report are given in Table 10.

Table 10. Net Present Value (NPV) of net whole-system benefits of FUSION

	Scenario	
(all values in £m)	**ST**	**CT**
PV of whole-system benefits	6,165	17,301
PV of cost	-3,216	-11,506
Net Present Value (NPV)	**2,950**	**5,791**

A clear finding from the results is that, once the cost of implementing FUSION and the cost of enabling residential DSR is considered, the PV of gross whole-system benefits outweigh the PV of the costs. In other words, there is a positive NPV of the FUSION rollout estimated at £2.95bn for the ST scenario and £5.79bn for the CT scenario.

These results suggest that there is a positive business case for FUSION from the whole-system perspective. The cost associated with its implementation, i.e., the required software and hardware interfaces, as well as the cost of tapping into residential demand-side flexibility resources is clearly lower than the system benefits quantified using a whole-system modelling approach.

Most of the whole-system value of FUSION arises from the avoided cost of investing into other forms of flexibility, in particular energy storage, interconnectors and peaking generation capacity, as well as from avoiding distribution network reinforcement. Given that the requirements for flexibility resources in the future GB power system will increase substantially to accommodate ever higher penetrations of variable renewables, the potential for cost savings through displacing a part of investment into other flexible resources will also be significant, likely outweighing the costs required to implement a distributed flexibility concept such as FUSION.

5.4. System benefit of FUSION per unit of flexible energy and flexible capacity

Another useful way of studying costs and benefits of distributed flexible resources in cases where there is high uncertainty around their implementation cost is to express the (gross) system benefits per unit of flexible capacity or per unit of flexible energy use, without considering the cost of delivering or enabling this flexibility. To this end, this section quantifies the gross system benefits of residential DSR assumed to be unlocked through FUSION. This approach allows for making an estimate on what would be a justifiable upper limit for the cost of implementing FUSION in residential DSR resources.

The results of the whole-system studies presented in the previous section were used to carry out the calculation of gross system benefits per unit of DSR capacity or energy assumed to be enabled through FUSION. Calculated values of per-unit system benefits are presented in Table 11.

Table 11. Gross system benefits of FUSION expressed per unit of flexible DSR volume

	Year	
Scenario	**2035**	**2050**
Benefits per unit of flexible energy (£/MWh)		
System Transformation	31.4	36.3
Consumer Transformation	43.7	51.3

Benefits per unit of flexible capacity (£/kW/yr)		
System Transformation	39.5	42.5
Consumer Transformation	36.1	32.5

In terms of benefits per unit of flexible DSR energy enabled through FUSION, the results suggest a range of £31-36/MWh for the System Transformation scenario, and £44-51/MWh for the Consumer Transformation scenario. Values in 2050 are observed to be higher than in 2035 as the need for flexibility increases over time. When expressed per unit of flexible capacity unlocked by FUSION, the values of £40-42/kW/yr in the System Transformation scenario, and £32-36/kW/yr in the Consumer Transformation scenario are observed. The values per unit of capacity tend to be lower in the CT scenario and decrease between 2035 and 2050 because of a significantly higher flexible capacity assumed to exist in that scenario (especially in 2050) due to higher assumptions on electrification of heat and transport demand.

Note that due to the way these gross benefits have been calculated, the values that a flexible asset would be delivering to the system through its capacity and through its energy shifting should not be added together to find the total system benefit.

5.5. Key observations

Quantitative modelling assessed the whole-energy system implications of large-scale deployment of FUSION concept in the context of GB electricity sector decarbonisation, specifically evaluating the benefits of FUSION concept and its ability to unlock distributed flexibility resources at the customer side.

Key findings from the cost-benefit analysis include:

- The cost of implementation and enablement associated with FUSION is estimated to be between 40% and 70% of gross whole-system benefits across various scenarios, resulting in net system benefits of FUSION ranging from £216m/yr in the ST scenario in 2035 to £654m/yr in the CT scenario in 2050.

- The PV of FUSION deployment cost was estimated at £3.2bn in the ST scenario and £11.5bn in the CT scenario. The PV of corresponding whole-system benefits was found to vary in the range between £6.2bn and £17.3bn across the two system scenarios. This suggests that a positive NPV of net system benefits of FUSION ranging between £2.9bn and £5.8bn for the ST and CT scenarios, respectively.

- The results suggest that there is positive business case for FUSION from the whole-system perspective due to its gross benefits exceeding the implementation cost, mostly associated with implementing the required software and hardware interfaces and with enabling residential DSR resources.

- The whole-system value of FUSION is predominantly associated with the avoided cost of investing into other forms of flexibility, such as energy storage, interconnectors or peaking generation, as well as the avoided cost of distribution network reinforcement. Increasing requirements for flexibility in the future GB power system required to accommodate high penetrations of variable renewables will lead to significant net system cost savings delivered through FUSION concept.

- Gross system benefits per unit of residential DSR volume unlocked through FUSION are also used to provide an estimate on the upper limit for the cost of implementing FUSION. In terms of benefits per unit of flexible energy use, the results suggest a range of £31-36/MWh for the ST scenario, and £44-51/MWh for the CT scenario, with values increasing between 2035 and 2050. When expressed per unit of flexible capacity, the benefits of FUSION are found to be £40-42/kW/yr in the ST scenario, and £32-36/kW/yr in the CT scenario.

6. Key conclusions

Based on the FUSION trial data, this report has carried out a quantitative analysis of local network benefits of USEF, as well as estimated the benefits of the concept for the GB-wide distribution network and the whole electricity system. This assessment was complemented by a cost-benefit analysis of FUSION as well as the analysis of key regulatory, policy and market aspects relevant for a successful deployment of FUSION. The results presented in the report suggest that although the benefits for the current networks and the system may be lower due to lower demand and considerable headroom in the existing network infrastructure, the future benefit of the FUSION concept, provided it can deliver additional distributed flexibility to the market and improve the reliability of flexibility services, could be very significant.

The analysis of the local HV network in the FUSION trial area assumed that USEF improves the reliability of delivery of flexible services compared to the BaU scenario. Flexibility assets trialled in FUSION were connected to three different HV feeders, of which only one had thermal-driven congestion issues that could be mitigated by flexibility (voltage-driven congestion was not observed in the trial network). FUSION trial data suggested that the reliability of delivering flexibility services in the USEF scenario was 73%, while the corresponding value in the BaU scenario was 65%, based on previous flexibility projects.

Two main benefits of USEF vs. the BaU scenario for the local HV network have been considered: i) improvement in the security of supply and ii) benefit from deferred network investment and reduced supply interruptions. Using the Effective Load Carrying Capability (ELCC) approach for the congested HV feeder, it was found that the additional contribution to security of supply in USEF vs. BaU scenario is about 0.2% of feeder peak demand that could be additionally accommodated by the feeder without the need for reinforcement. For the other two feeders the present benefits are minimal given that their peak demand is significantly below their rated capacity. Nevertheless, there would still be future benefits as the demand on those two feeders increases. Potential savings of USEF vs. BaU on the congested feeder resulting from network upgrade deferral and reduced Customer Minutes Lost (CML) were estimated at £695-728, which was 13% higher than the benefits of BaU-based flexibility. The magnitude of incremental benefits of USEF is not very high in the present circumstances; however, future electricity demand increase driven by electrification of heat and transport can be expected to lead to significantly higher benefits of FUSION, both because of higher network loading and due to FUSION potentially unlocking additional sources of flexibility.

Based on the premise that FUSION could unlock additional sources of flexibility in the residential sector, the report also assessed the whole-system benefit for the GB electricity system. System benefits are found to vary in magnitude depending on the scenario and time horizon, with higher benefits in scenarios with higher electrification, and a significant increase in benefits between 2035 and 2050. In the System Transformation (ST) scenario the incremental annualised benefits of FUSION more than double between 2035 and 2050, from £0.38bn/yr to £1.08bn/yr, while in the Consumer Transformation (CT) scenario, characterised by more accelerated electrification, the value reaches £1.40bn/yr in 2035 and increases to £2.22bn/yr in 2050. Looking at GB-wide distribution network investment, the strategic cumulative reinforcement deferral delivered by FUSION in 2035 is estimated at £8.1-8.7bn, reducing to £2.1-4.4bn in 2050.

In the cost-benefit analysis presented in the report the cost of implementation and enablement of residential flexibility required to deploy FUSION was estimated to be about 40-70% of gross whole-system benefits, resulting in net system benefits of FUSION ranging between £216-£654m/yr. The Net Present Value (NPV) of net system benefits of FUSION was estimated at between £2.9bn and £5.8bn. Based on the modelling results, FUSION was found to provide a positive net system benefit if its deployment cost for residential DSR is lower than £31-51/MWh of flexible energy demand, or lower than £32-42 per kW of flexible capacity per year.

7. References

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