Solent Achieving Value from Efficiency

SSET206

LCNF Tier 2 SDRC 4 Create commercial energy efficiency measures

Scottish and Southern Electricity Networks (SSEN) is the new trading name of Scottish and Southern Energy Power Distribution (SSEPD), the parent company of Southern Electricity Power Distribution (SEPD), Scottish Hydro Electricity Power Distribution (SHEPD) and Scottish Hydro Electricity Transmission. SEPD remains the contracted delivery body for this LCNF Project.

Prepared By

Document Owner(s)	Project/Organisation Role
Charlie Edwards	SAVE Project Manager
Joshua Martin	Modelling Analyst

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Executive Summary

Solent Achieving Value through Efficiency (SAVE) is a Low Carbon Network Fund (LCNF) project that aims to robustly trial and establish to what extent energy efficiency measures can be considered as a cost effective, predictable and sustainable tool for managing peak demand as an alternative to network reinforcement. The core of the project looks to understand the demand side response (DSR) capabilities of domestic customers through four key methods: LED lighting; data informed engagement; data informed engagement and price signals; community energy coaching. In considering how a DNO might implement each of these mechanisms in business as usual operation it is crucial that the commercial mechanisms encompassing the industry have been considered, identified and where necessary, changes suggested.

Within this report the project looks primarily at the exploration of how a DNO might pass price signals onto its customers in a complex regulatory environment, considering closely; industry integration, geographical levels and differing tariff structures. In order to best address this the report is broken down into four key sections first looking at the electricity industry's history of flexible and tiered tariffs, before discussing current industry mechanisms through which a DNO might pass price signals on to customers; the final two sections will look at how the SAVE project's live trials and work packages are expanding industry understanding into the calculation and impact of DNO led price signalling.

Drawing upon learning from tiered pricing mechanisms already in place should be at the centre of any future DNO interaction. Using the example of Economy 7 the report shows how the uptake of a tiered pricing mechanism needs to consider customer interaction and marketing closely alongside any commercial mechanisms. The report shows how the success of Economy 7 was supported through dual-layered customer engagement, from both within the electricity industry and the manufacturers providing the facilitating technology. This section continues to look at mechanisms currently in place at both transmission and distribution levels of the network to encourage commercial load-shifting, namely a critical peak price (CPP) mechanism and a more commonly known tiered approach, time of use (TOU) pricing.

In exploring the current regulatory playing field the report suggests seven mechanisms which a DNO might utilise to pass price signals to its customers. This includes those mechanisms which issue payment directly from the DNO to customers and those which look to pass price signals through existing mechanisms with suppliers; as well as those mechanisms within and outside of the industry's current Distribution Connection and Use of System Agreement (DCUSA). Specific changes and costs foreseen are highlighted and where applicable consideration of the impact on Distribution Use of System (DUoS) charging is explored. Recommendations and a forward-focused strategy to develop this work is highlighted in Section 6: Recommendations and Learning Outcomes. Section 6 provides

insight into the direction of reporting which will be taken in SDRC 8.4 DNO price signals direct to customer's trial report and SDRC 8.5 Network Pricing Model Report to be delivered at project closedown in June 2019.

Sections 4 and 5 of this report show the current work being undertaken on the SAVE project, initially focusing on the modelling package of work, primarily detailing the Network Pricing Model that has been developed. The Network Pricing Model is one of three models that will fit into the project's final Network Investment Tool, designed to allow network planners to directly compare smart interventions in a given area against conventional forms of reinforcement. Built upon a range of inputs and forecasting mechanisms the Network Pricing model has the capability to output the expected cost saving (over time) as a result of a given smart intervention using an scenario tree diagram mechanism. This model can also provide insight into the potential level of payment available to a DNO in order to incentivise domestic DSR; which leads on directly to the live trials in SAVE. The live trials within SAVE look to provide initial evidence as to the level of load-reduction that may ensue from incentivisation of domestic customers. Whilst initial incentivisation within SAVE's first (of three) trial window did not see any increased impact of price signals against data informed engagement alone, the report shows how the project is using these findings as a baseline to build upon for future trial iterations.

1 Introduction

1.1 Background

Solent Achieving Value from Efficiency (SAVE) is a Low Carbon Network Fund project that aims to robustly trial and establish to what extent energy efficiency measures can be considered as a cost effective, predictable and sustainable tool for managing peak demand as an alternative to network reinforcement. The project will target domestic customers only in the Solent and surrounding area in the South of England, which is representative of much of the UK, and the measures to be trialled will include deploying a technology, offering a commercial incentive and taking an innovative approach to engagement.

The SAVE project is divided into four main methods of domestic demand side response (DSR), namely LED engagement, data informed engagement, data informed engagement with price signals and community energy coaching. Different means of testing these methods will be explored through three trial windows between January 2017 and December 2018. Full updates detailing the evolution of these methods can be found in the SAVE six monthly project progress reports (PPR's).

Through execution of the SAVE project, SSEN have ensured upmost attention be paid, not just to the quality of project outcomes, building upon previous industry learning; but also in ensuring both scalability and replicability of trials. The purpose of this report is to explore the wider commercial and regulatory domain surrounding a DNO's implementation of domestic DSR. This is achieved through exploration of two key questions:

1. How might a DNO pass DSR signals (specifically price signals) to a select customer base?
2. What level of capital is likely to be available to a DNO to spend on smart interventions within specific geographic boundaries and what impact is this likely to enact?

In order to explore the 'how' element of this question the SAVE Project team have sought expert advise (internally and externally) on both historic and current industry direction with regards time of use (ToU) charging. Layered within this, the report has investigated how innovative new avenues of passing incentives to customers may be explored in future, in addition to impacts on third parties, geographical implications and variance caused by different ToU tariffs (i.e. time-bands and critical peak pricing (CPP)). These methods are explored within section 3 of the report and address Project Outcome A in section 1.2 below.

Within the next section of the report it is then explored at what level a price signal might be enacted, this will be done through an introduction to the project's pricing model, its required inputs, the model's outputs and its functionality. The network pricing model will form the core of this this report, detailing at what level certain commercial mechanisms, explored in section 3, may be set by a DNO (i.e. DUoS) and how this may look to its customers. This will address Project Outcomes B and C detailed below.

Furthermore evidence from the pricing model is supplemented by evidence from SAVE's first live trial window (January 2017-March 2017) detailing the impact of certain incentive mechanisms on customers and how this may be amended moving into trial period 2 given the learning obtained from the network pricing model.

Finally the report will conclude by forming thoughts on a regulatory and incentive model for DNOs to use in RIIO (Project Outcome D). This will evolve as the project develops, learning around the impact from price signals grows and wider industry discussion around market mechanisms advances (including Distribution System Operation and access to data).

1.2 Project Outcomes

Within the SAVE Project Bid document (SSET206) it is defined that SDRC 4 will:

Establish the pricing model and process for passing DNO price signals direct to customers

This report confirms this deliverable has been met and provides evidence for the below four key related project commitments (as per SAVE Project Bid):

A. *Investigate feasibility of modifying charging methodologies (DUoS) to reward changes in consumption, and identify what changes (contractual/charging methodology) would be necessary to implement it.*
B. *Create a pricing model to reward customers for changing consumption behaviour, estimating the value of the change in demand to the network*
C. *Establish the pricing model and processes for passing DNO price signals direct to customers*
D. *Come up with thoughts on a regulatory model and incentive model for DNOs to use in RIIO*[1]

At point of submission, the SAVE project identified seven key knowledge gaps and four learning outcomes to be addressed, those which can be built upon through this SDRC are detailed below:

- *[Learning Outcome]- to determine the merits of DNOs interacting with customers on energy efficiency measures as opposed to suppliers or other parties*
- *[Knowledge gap]- What engagement approaches are available to DNOs to facilitate uptake of energy efficiency measures by domestic customers?*

[1] Whilst point D will initially be addressed within this SDRC as SAVE matures further/amended recommendations will likely develop.

- *[Knowledge gap]- What do DNO led energy efficiency campaigns look like and how can they be run successfully?*

1.3 Method Definitions

The SAVE project bid document (SSET206) outlines four main methods of intervention that will be tested within the project. These were originally named as follows:
Method 1 (M1)- LED engagement
Method 2 (M2)- Data informed engagement
Method 3 (M3)- Data informed engagement and price signals
Method 4 (M4)- Community Energy Coaching

This however did not provide a reference number to the projects control group population. Throughout delivery of the project to ease identification of the methods being trialled each was re-named as follows:
Trial Group 1 (TG1)- Control Group
Trial Group 2 (TG2)- LED Lighting
Trial Group 3 (TG3)- Data informed engagement and price signals
Trial Group 4 (TG4)- Data informed engagement
Community Energy Coaching Trials (CEC or M4)

To avoid confusion and risk mismatch between delivery and reporting the project came to the conclusion the methods were better referred to by these names. Within this document all interventions will be referred to under their revised names.

2 Current DNO price signals

Prior to exploring future methods of payment for ToU tariffs it is important to acknowledge current electricity price signals used to reflect network loading challenges. Three key mechanisms are explored within this section, providing an introduction to the evolving market surrounding the Distribution Connection Use of System Agreement (DCUSA). Initially the report explores previous successful implementation of domestic ToU charging notably the introduction of Economy 7[2] in 1978. Secondly transmission mechanisms for billing customers to reflect network charges are referenced, most notably Triads. Finally the section details mechanisms of pricing currently used to reflect

[2] Economy 10 is another, less common, example of differential electricity tariffs whereby off-peak periods last 10 hours as opposed 7.

distribution network loading by introducing the billing of non-domestic premises and how this has been translated at domestic customer level.

2.1 Economy 7

Economy 7 is a two tiered electricity tariff with cheaper rates available during the night (midnight to 7am) than those during the day (which are often close to 40% more expensive (USwitch, 2017)) implemented in 1978 to benefit homes with storage heaters and to manage growing off peak generation by shifting consumption to off-peak. Whilst Economy 7 was created largely in order to manage changes in electricity generation (movement towards less flexible nuclear power-plants) the apparent knock-on effects at network level were also of consideration. On one hand shifting consumption from peak periods to off-peak will benefit the network, however if all customers within a given area on Economy 7 (as is typical given it is usually flats or homes off the gas network that can benefit from Economy 7) came online at the same time, then there is potential for significant local peaking in demand when reduced night-time Economy 7 charging began. Resultantly radio tele-switching systems, using the BBC Radio 4 broadcasting services are used to control systems and vary their timing (Ofgem, 2013).

Given the set-up of Economy 7, namely to address the broader strategic objectives of a nationalised industry competing with gas as opposed to the current imperatives of the distribution network, the commercial mechanisms behind the tariff are not explored within this report. However, the marketing of this tariff shows the potential of what can be achieved once the efforts of the diverse stakeholders are leveraged. Key features were as follows:

- National marketing campaigns that were initiated and funded by the electricity council.
- Local marketing campaigns including TV, press and radio.
- Marketing directed at builders, installers and architects, to promote the benefits of electric heating and TOU tariffs. The aim was to encourage those specifying heating systems to use electric heating, an example of which was the medallion homes specification. Sales and marketing also included sales staff who would visit builders, installers and architects.
- Marketing directed at social housing landlords and local authorities.
- Centrally funded R&D at Capenhurst. This research helped to develop the equipment and controls to utilise TOUs as well as case studies to demonstrate the benefits.
- Economy 7 was so successful they created a night time load peak which was determined by the settings on each customer’s mechanical time switches. These time switches couldn’t be easily adjusted and this prompted the electricity supply industry and BBC to work together to develop radio tele-switching to provide diversity.

This wide ranging approach to promoting Economy 7 and its facilitating technology led to rapid growth of the initiative and despite a subsequent shift towards gas heating around 4 million households across the UK still have Economy 7 meters (This is Money, 2014). As trajectories expect rising gas prices to cause shifts 'full-cycle' back to electric heating, the appeal of Economy 7 and other tiered pricing mechanisms are likely subject to change once again.

The customer engagement approach adopted to support the Economy 7 pricing stricture is purposefully discussed above as opposed the commercial mechanisms to highlight the importance of social interactions alongside the economic value case. Advertising campaigns may be necessary to ensure successful implementation of tiered tariffs, customer uptake is likely to be maximised if paired with enabling and facilitating technologies i.e. the Navetas 'Loop' or British Gas 'Hive',.

2.2 Transmission mechanisms

National Grid recovers its allowed revenues via TNUoS which is paid for by generators, suppliers and transmission-connected demand customers (National Grid 2016). Suppliers then pass this cost onto their customers through their own tariffs. The size of the charge recovered from each supplier depends upon: their customers' energy consumption, location of their customers and consumption during triad periods.

2.2.1 Triads

Triads are the three half hour periods of the highest demand between November and February, which have at least 10 days separation between instances.

Given a significant proportion of customer tariffs may be determined by triads, triad avoidance is becoming an increasing topic amongst large users of electricity. This however can be challenging given triads are not known in advance, nonetheless many suppliers and aggregators will do their best to forecast when they may occur (National Grid 2015).

With Triads representing a significant proportion of costs for half-hourly billed customers (excluding smart meters) the system acts almost as a form of tiered tariff called Critical Peak Pricing (CPP) where prices may spike for a limited number of times during the year in order to represent a specific situation. In the majority of instances distribution network reinforcement is triggered by a constraint which only occurs a few days of the year for a limited time-period; in such areas CPP could signal an ideal solution. There are two routes through which such pricing may be implemented; that which requires instantaneous response, much like triads, or that which can be signalled through a form of prior warning. It is the latter which would likely be best suited to a domestic market.

Learning from the forecasting and aggregation carried out on SSEN's Thames Valley Vision (NTVV) Project looked to model customer demand in given areas of the network and how this may vary with uptake of smart technologies such as Electric Vehicles (EV's), Solar Photovoltaics (PV) and Heat Pumps (HP). Given this modelling a DNO could predict when it expected demand peaks to occur within a given area, their size and at what network level[3].

2.3 DNO led half-hourly billing

2.3.1 Pre April 2015 charging arrangements

Traditionally there were two broad mechanisms through which qualifying customers may experience tiered billing. Namely this includes two-rate tariffs and red amber green (RAG) tariffs. Two rate tariffs are billed using what is called a 'supercustomer' approach, this compiles consumption at a group level, whereas RAG tariffs are billed on an individual Meter Point Administration Number (MPAN) consumption level. Domestic customers could qualify for two-rate tariffs if they have an Economy 7 or similar meter installed. The meter will record separate consumption readings for these two rates based on the time pattern configuration of the meter. There is typically a Day rate and Night rate, where the DUoS (distribution use of system) p/kWh charge is lower during the Night. However, the RAG tariffs were largely limited to non-domestic customers as they are required to have Half-Hourly meters installed.

2.3.2 SEPD DUoS charge statement April 2015

In April 2015 an industry change (DCUSA Change Proposal 179) implemented two RAG ToU tariffs for Low Voltage (LV) Network Domestic and LV Network Non-Domestic customers, this in turn prompted an industry change (Balancing and Settlement Code (BSC) Modification P300) to facilitate aggregated half-hourly (HH) settlement for these tariffs. This created a further mechanism for tiered billing; aggregated HH settlement using the 'supercustomer' approach, something that is more suited for large numbers of customers, such as the domestic market.

SEPD's April 2017 Use of System Charging Statement (SEPD 2017) defines the network's latest RAG time of use bandings under the Common Distribution Charging Methodology (CDCM) and is intended for use with half hourly settled customers[4]. These time bands are split into three key categories of red, amber and green, and are time of use time periods (see Figure 1 below). The red time period is intended to reflect peak load on the network, which means that demand/generation customers will have a higher p/kWh charge/credit. This in turn means that the amber and green are intended to reflect times of lower load on the network, and have lower p/kWh charges. For example, the LV Network Domestic demand tariff in April 2017 is 12.082p/kWh during the Red time period, 0.992p/kWh

[3] Given the input of relevant local information.

[4] Although these are not currently used for domestic customers with smart meters they do act as a test for the migration to smart metering

during the Amber time period and 0.238p/kWh during the Green time period. Whereas the HV Generation Non-Intermittent generation tariff in April 2017 is -4.022p/kWh during the Red time period, -0.191p/kWh during the Amber time period and -0.064p/kWh during the Green time period.

Time Bands for Half Hourly Metered Properties			
Time periods	Red Time Band	Amber Time Band	Green Time Band
Monday to Friday (Including Bank Holidays) All Year	16:30 - 19:30		
Monday to Friday (Including Bank Holidays) All Year		07:00 - 16:30 19:30 - 22:00	
Monday to Friday (Including Bank Holidays) All Year			00:00 - 07:00 22:00 - 24:00
Saturday and Sunday All Year		09:30 - 21:30	00:00 - 09:30 21:30 - 24:00
Notes	All the above times are in UK Clock time		

Figure 1 SEPD April 2017 time bands

3 Methods of payment

The project team have worked closely with both internal SSEN commercial experts and specialist consultants Reckon LLP in order to best understand the mechanisms through which a DNO might engage with domestic customers to provide DSR price signals. A formal report procured by the project and delivered by Reckon LLP can be found within Appendix A, whilst the section below looks to detail the methods of payment identified as well as potential challenges different approaches may face. Supporting the section below the project also discusses engagement with suppliers and the importance of both co-operation and co-ordination.

Before continuing this section it is recommended that the reader understands the four main assumptions and wider specific requirements relating to this work.

1. It is assumed that the nature, timings and level of payment would be determined through network planning (or/and the network investment tool).
2. If methods trialed within SAVE were to be rolled out more widely, DNOs may need to develop and maintain a database for customers eligible for payment.
3. It is possible to incorporate geographically varying incentive payments to customers within a distribution area. For payment options linked to DUoS, geographically varying tariff elements

would need to be specified in the tariff structure. For instance, this could be done by introducing several new tariffs, one for each geographical region within a distribution area.

4. A system would be needed to make payments to customers or their suppliers this would require robust arrangements to ensure that payments are only made to those customers that meet the DNO's eligibility criteria.

A full overview of these assumptions is outlined within paragraphs 16-28 of Appendix A.

Seven possible means through which a DNO might pursue payment mechanisms to its customers are assessed within the text below. Four of these options involve changes to the Distribution, Connection and Use of System Agreement (DCUSA). The seven options are:

a) Direct payments to customers
b) Indirect payments to customers through their supplier (outside DCUSA)
c) Indirect payment to customers through their supplier (within the scope of DCUSA)
d) Payments to suppliers (outside DCUSA)
e) Payments to suppliers (within DCUSA)
f) Payments to suppliers through credits against their DUoS bills (within the scope of DCUSA)
g) Payments to suppliers through special discounted DUoS tariffs (within the scope of DCUSA)

A summary of each option is displayed below, before assessing barriers, risks and limitations. These options were developed to explore a wide range of possible payment mechanisms and it should be recognised that some aspects may come with significant requirements in terms of the industry code changes required and potential impacts on data flows and the capabilities of current systems.

Option (a): Direct payment to customers

- This option involves the DNO making direct payments to eligible customers bypassing the supplier entirely.
- Under this option, the DNO would enter into a one-off or ongoing commercial relationship with the customer that allows payments to be made. DNOs currently do not have such a relationship with domestic customers, and so this would require new data flows and changes to DNO systems. It will also mean that DNOs would handle additional personal data relating to customers.

- We assume that a modern payment mechanism would be used, such as sending a pre-paid debit card or a code that customers can, using a website or telephone service, redeem either against a direct bank account credit or a voucher for a large retailer of their choice.
- A possible variation on this option would involve making the payment to a future technology provider that might offer energy efficiency services to the customer (e.g. a home hub provider that allows the customer to track and control energy use).

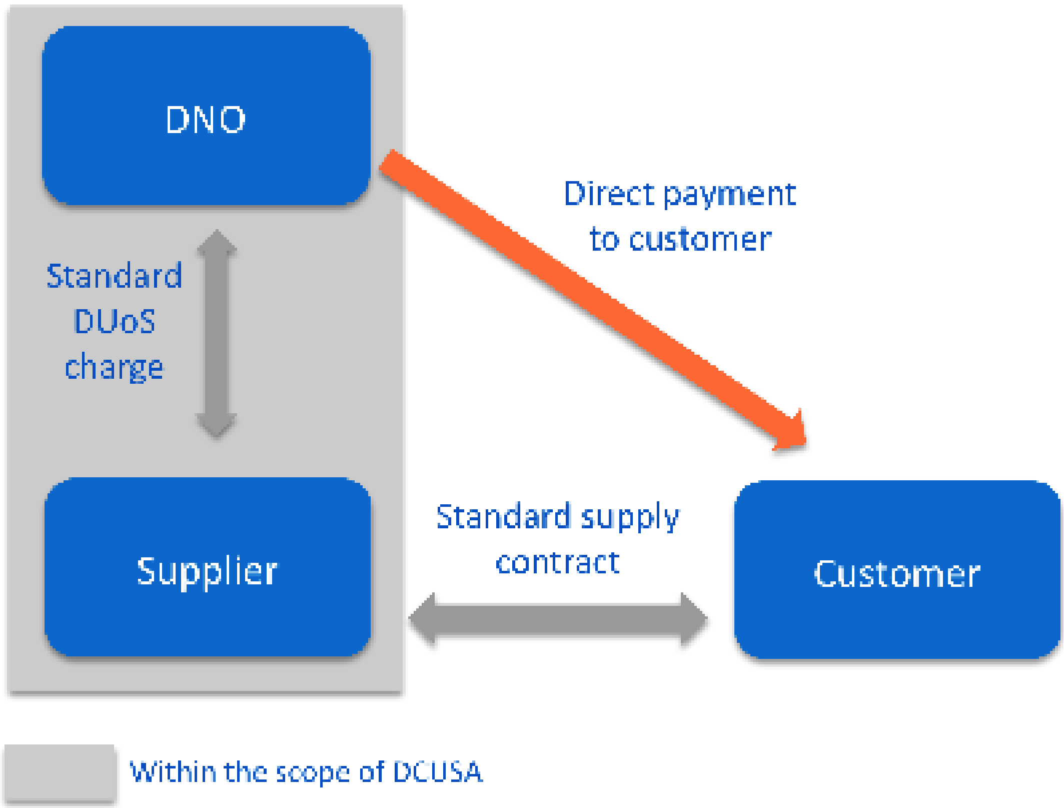


Figure 2 Schematic of direct payment to customers

Option (b): Indirect payments to customers through their supplier

- This option involves making payments to customers through the agency of their current supplier, outside the scope of DCUSA.
- The supplier may make the payment as a credit towards the customer's bill or prepayment meter account, or in any other way that the supplier chooses, on the instructions of the distribution business.
- There would need to be an agency agreement defining the supplier's obligation to pay the customer, and providing for a small handling fee to be paid by the distribution business to the supplier on top of the customer payment. The agency agreement would have to be entered separately with each supplier.

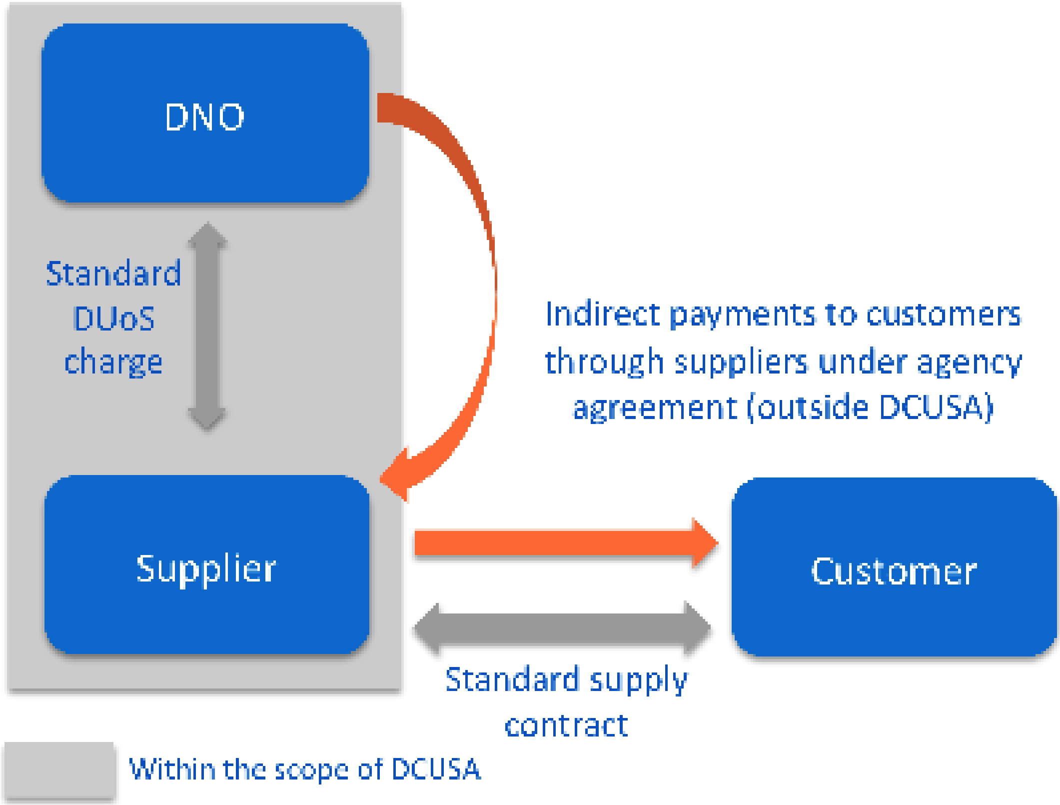


Figure 3 Schematic of indirect payments to customers through their supplier

Option (c): Indirect payments to customers through suppliers under DCUSA

- This option is a variant on option (b) that involves including within DCUSA a mechanism by which DNOs make a payment to suppliers that the suppliers are then required to pass on to designated customers.
- This option requires a change to DCUSA, which would be made through the DCUSA change governance process. The change would be subject to approval by Ofgem.
- The current arrangements within DCUSA for compensation payments that may be payable by DNOs to customers in relation to breaches of Guaranteed Performance Standards may serve as a template for this new arrangement.[5]
- The current arrangements for these payments obliges suppliers to "pass such payment to the Customer as soon as reasonably practicable and if, due to the [supplier's] delay, an additional payment becomes due […], then this additional payment shall be the liability of the [supplier].
- This agreement may include separate handling fees to cover the cost to suppliers of managing these payments.

[5] See section 2A, subsection 33 of DCUSA (version 9.2)

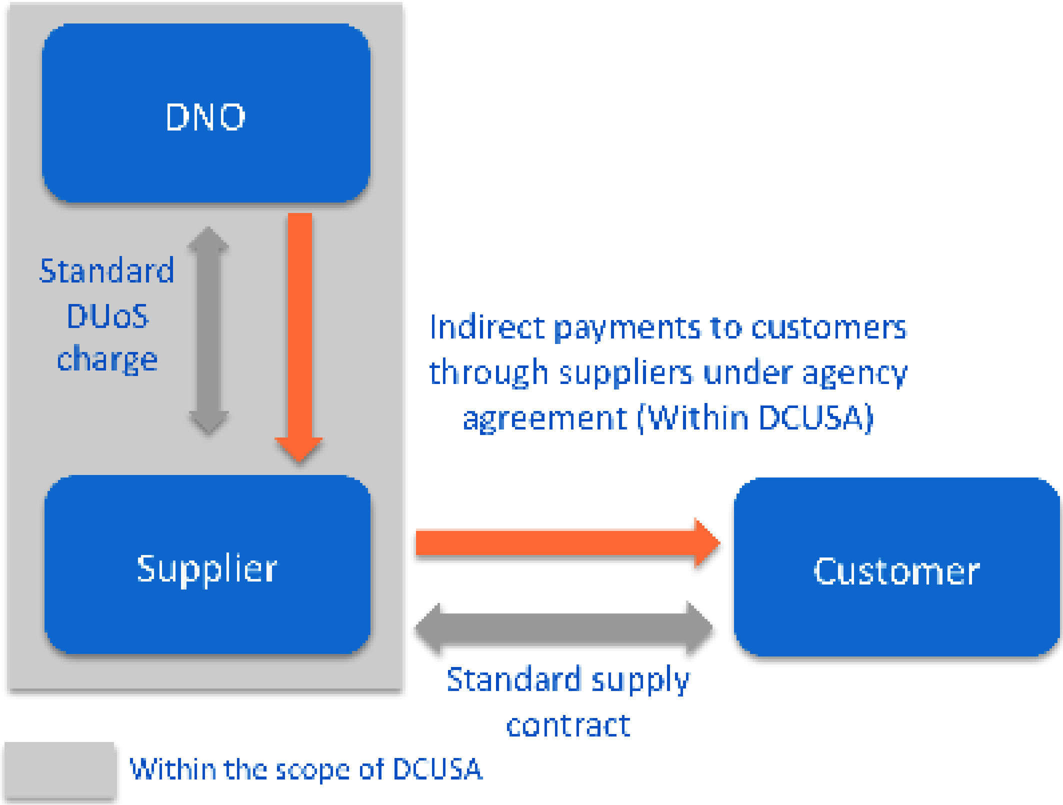


Figure 4 Schematic of indirect payment to customers through suppliers under DCUSA

Option (d): Payments to suppliers outside DCUSA

- Under this option, the DNO would make a payment to suppliers in relation to eligible customers served by those suppliers.
- The payment would be made outside the scope of DCUSA, and separate correspondence might therefore be needed to each supplier.
- Under this option, there would be no explicit requirement or obligation on suppliers to pass on the payment to customers.
- If there is sufficient competition between suppliers to serve those customers, we expect that the payments would be passed on by suppliers. However, eligible customers would need to be aware of these payments and may need to shop around until they find a supplier that is willing to pass these payments onwards.

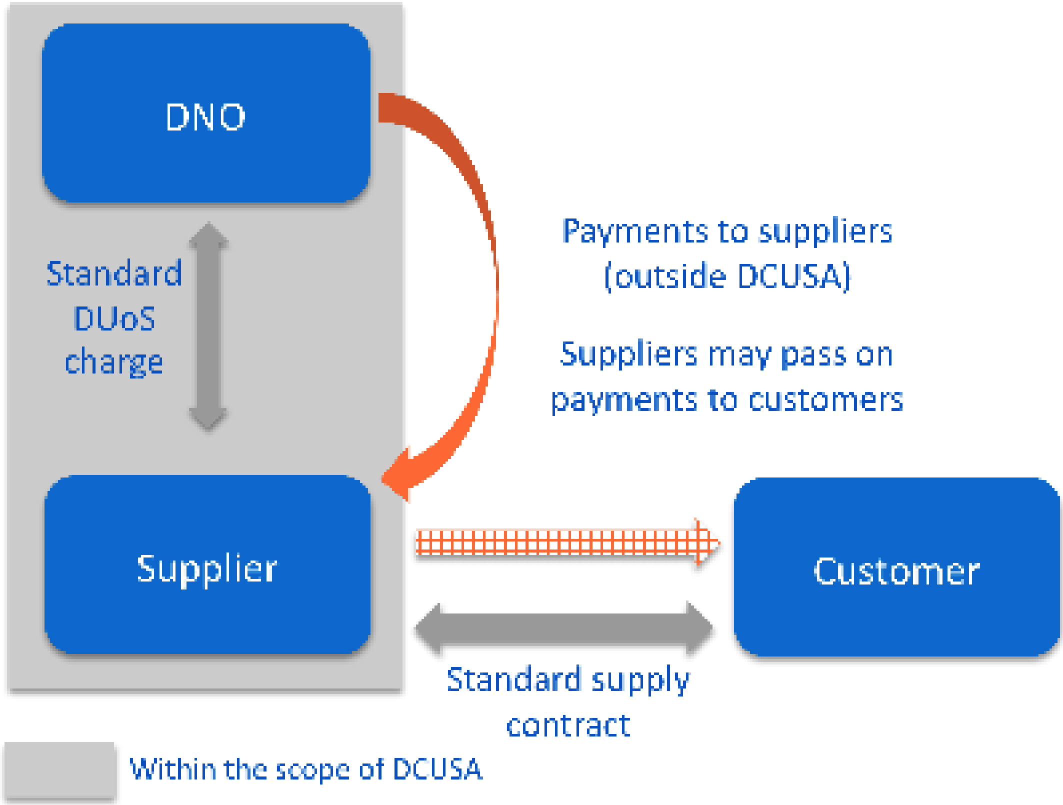


Figure 5 Schematic of payments to suppliers outside DCUSA

Option (e): Payments to suppliers under DCUSA

- This option is a variant on option (c) that involves including within DCUSA a mechanism by which DNOs make a payment to suppliers in respect of eligible customers served by them. Under this option, there would be no explicit requirement for the supplier to pass on the payment to customers.
- However, competition between suppliers to serve those customers may be sufficient to ensure that the payments are passed on.
- This option requires a change to DCUSA, which would be made through the DCUSA change governance process. The change would be subject to approval by Ofgem.

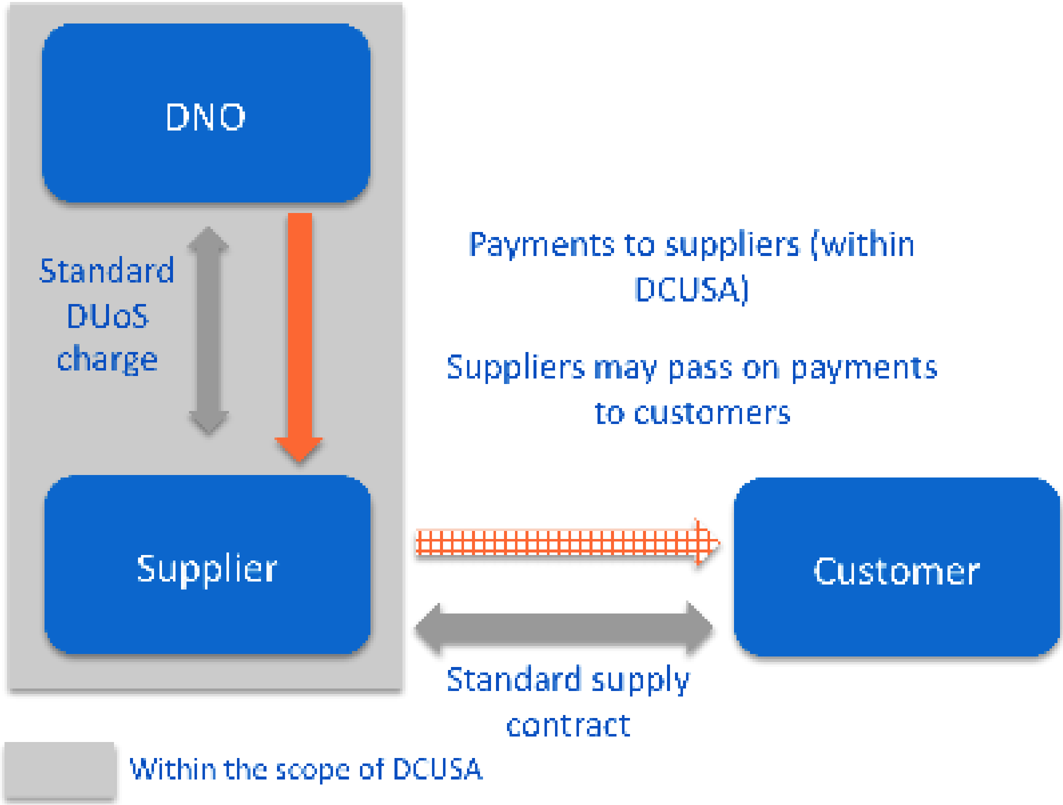


Figure 6 Schematic of payment to suppliers under DCUSA

Option (f): Payments to suppliers through credits against their DUoS bills

- Under this option, DNOs would determine a payment amount for each supplier, representing the aggregate payment due in respect of all customers served by that supplier.
- This payment would be expressed as an aggregate credit or discount against the total DUoS charges due from the supplier. The payment would not be linked to individual customers or their consumption. The total amounts due to each supplier would depend on the number of eligible customers in their supply portfolio within each DNO area, and if applicable, the aggregate consumption of those customers in particular periods.
- There would be no explicit requirement or obligation on suppliers to pass on the payment to customers. However, competition between suppliers to serve those customers may be sufficient to ensure that the payments are passed on.

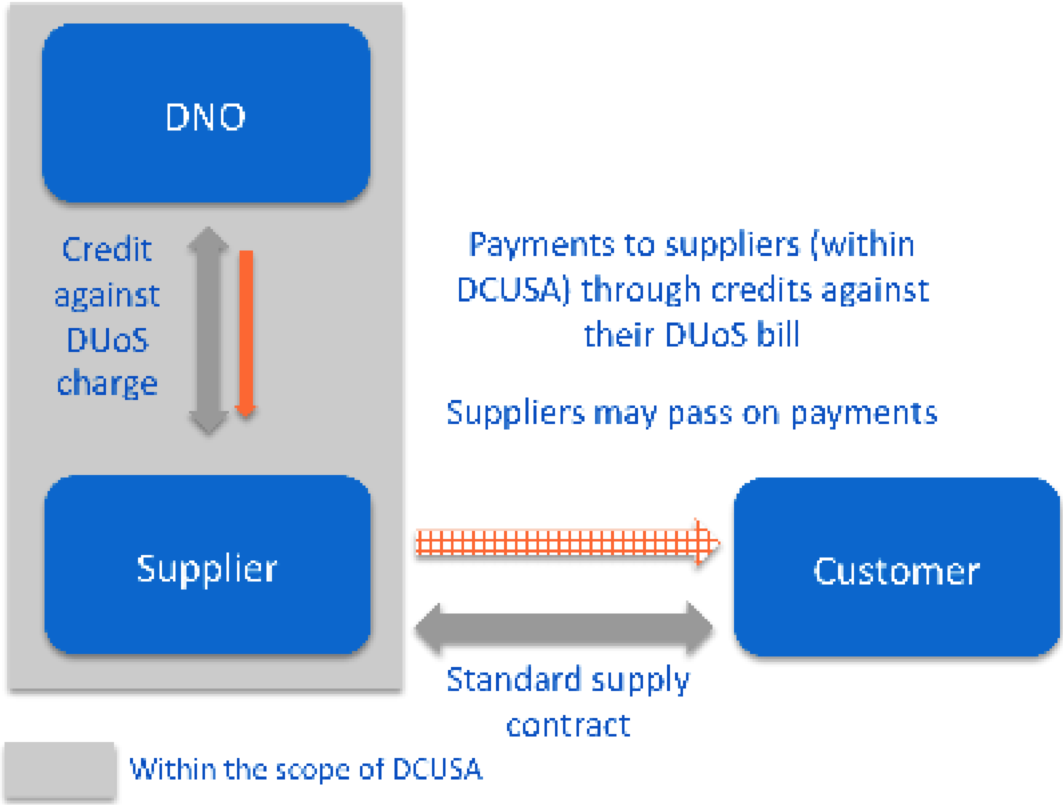


Figure 7 Schematic of payment to suppliers through credits against their DUoS bills

Option (g): Payments to suppliers through special DUoS tariffs

- Under this option, the special DUoS tariffs would be created for eligible customers.
- There are two ways in which the special DUoS tariff can be structured to give effect to the payment.
    - The special tariff could include a discounted or negative fixed charge expressed in p/day/MPAN.
    - The special tariff could include different unit charging rates for consumption at different times of the day (i.e. a time of use tariff).
- The current DUoS charging arrangements (the CDCM) already include domestic time of use tariffs (i.e. the Domestic two rate and LV Network Domestic tariffs). Additional time of use tariffs could be introduced if these existing tariffs are not seen to provide appropriate signals. Time of use DUoS tariffs that involve more than two rates in a day can only be applied in respect of customers that are half hourly settled.
- Multiple special time of use tariffs can be created to provide different payment rates for geographical regions within each distribution area.
- This option involves changes to the DUoS charging methodology within DCUSA through the change governance process. The next section sets out a brief overview of the criteria that any

DUoS charging methodology change proposal would need to meet before it is approved by Ofgem.

- Under this option, there would be no explicit requirement or obligation on suppliers to pass on the payment to customers. It is currently up to suppliers to decide how, if at all, to pass on DUoS charge signals to their customers. However, competition between suppliers to serve those customers may be sufficient to ensure that DUoS signals are passed on.

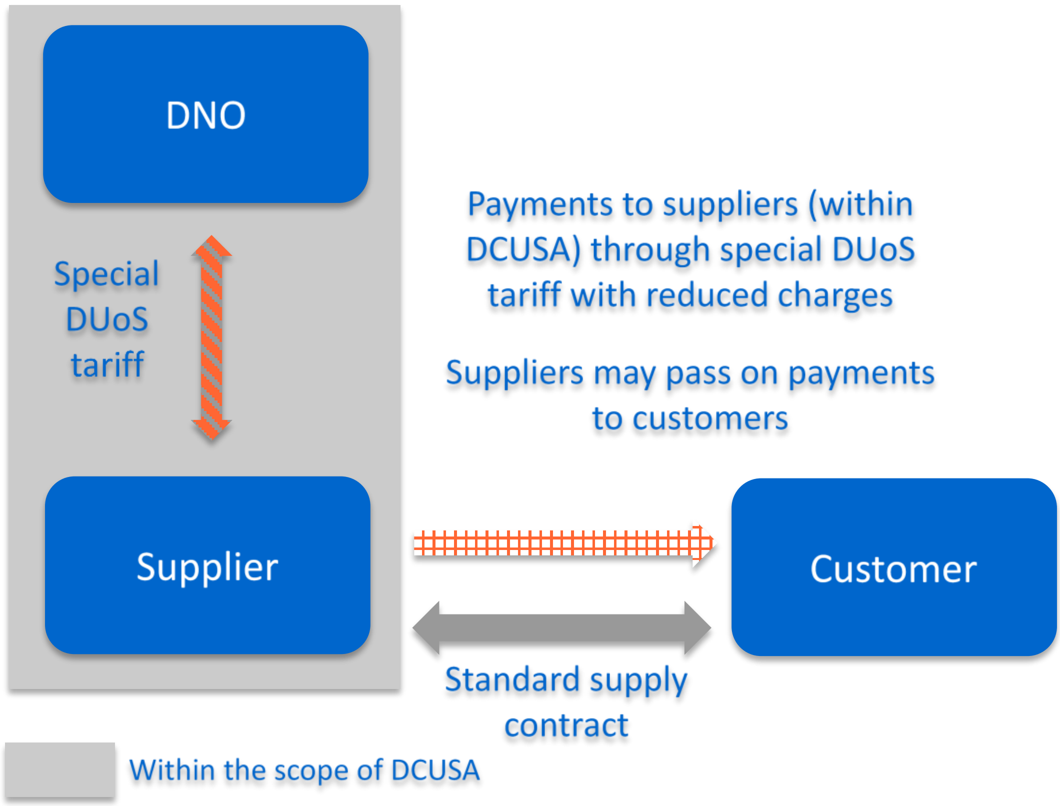


Figure 8 Schematic of payment to suppliers through special DUoS tariffs

3.1 Relevant Barriers, risks and limitations

Having outlined and assessed each means of passing price signals to customers, the section below identifies the sources of barriers, risks and limitations which could affect the implementation of each option, and identifies ways in which barriers might be overcome and risks might be mitigated.

3.1.1 Barriers and risks arising from the RIIO price control framework

All DNO licensees operate under Ofgem's RIIO price control framework. The current price control (RIIO ED1) runs from 1 April 2015 to 31 March 2023.[6]

Under the RIIO framework, Ofgem sets outputs to be delivered by each DNO and provides expenditure allowances that enable DNOs to fund the cost of meeting those outputs. Expenditure allowances are then turned into maximum allowed revenues that may be recovered through distribution use of system charges.

Under this framework, total expenditure allowances are typically fixed in advance at the start of the price control period. Any under or overspends against these allowances are subject to the totex incentive mechanism, whereby customers fund a fixed proportion of any overspend (the rest is funded by investors in the DNO), and receive a fixed proportion of any underspends (and the rest goes to investors in the DNO).

Under every option except option (g) set out in the previous section, payments to customers or suppliers may be seen as costs incurred by the DNO business that could potentially deliver cost savings through reduced network investment in the future.

From a price control perspective, DNOs are allowed to recover efficiently incurred costs through DUoS charges, provided these are well justified.. There is some precedent in price controls for allowed costs that take the form of payments to customers. For instance, under Ofgem's current RIIO ED1 price controls, payments to customers for demand side management actions taken by customers may be treated in the same way as network reinforcement costs.

DNO expenditure allowances for the RIIO ED1 period (April 2015 to March 2023) were set by Ofgem in 2014. Under the RIIO framework, actual qualifying expenditure reported by DNOs in each year would be set against the allowed expenditure in that year. Any underspends or overspends against allowances would be shared between customers and investors in the DNO under the totex incentive mechanism.

Any payments to customers that are treated as qualifying expenditure would reduce the amount of underspend or increase the amount of overspend relative to the expenditure allowance for the year. This means that, taking expenditure allowances as fixed, each £1 of incentive payments made would be part funded by DNO investors, at least in the short term.

Countering this effect, any reduction in network reinforcement expenditure that may be attributed to the payment would increase the amount of underspend or reduce the amount of overspend relative to

[6] See https://www.ofgem.gov.uk/network-regulation-riio-model/riio-ed1-price-control for further details and recent publications.

the expenditure allowance for the year in which the reinforcement might have been expected to take place.

Provided the reduction in network reinforcement expenditure is tangible, immediate and exceeds the value of incentive payments made to customers, the net effect on the DNO and its customers should be positive.

a) The long-term impact is more difficult to forecast, particularly if the impact in terms of lower network reinforcement expenditure is spread over several years such that it spans multiple price control periods. If DSR becomes an established tool for network management it can be expected the lower costs associated with implementation compared to network reinforcement will be factored into future price controls.

It may be possible to secure Ofgem approval to treat payments under options (a) to (f) as negative revenue, in a similar way to the current treatment of payments to embedded generators. In that case, these payments would be recoverable from other customers through the DNOs' DUoS charges in the same year as the payment is made. This would require a change to the current price control arrangements and revenue reporting frameworks.

Under option (g), i.e. introducing a special DUoS tariff, it is unlikely that there would be an interaction with the price control framework. Provided Ofgem continues with a total revenue control for DNOs, any shortfall in revenues caused by an approved change in the DUoS methodology can be recovered from charges to all users.

In all cases, it will be key to understand the overall impact on customers of any options pursued, including consideration of whether it is appropriate for all users to fund incentives to particular groups of customers.

3.1.2 Impact of the current structure of DUoS charges

The current methodology for setting DUoS charges for domestic customers is set out within Schedule 16 of DCUSA (the Common Distribution Charging Methodology, or the CDCM).

The CDCM determines charges for customers, which when applied to forecast volumes of demand, would recover the DNOs' annual allowed revenue.

The current version of the CDCM includes the following tariff components.

a) Unit charges based on consumption (p/kWh)
b) Fixed charge (p/day/MPAN)
c) Capacity charges and exceeded capacity charges (p/kVA/day)
d) Reactive power charges (p/kVArh)

Currently, domestic customers are only liable for unit charges and fixed charges. The current CDCM includes both half hourly and non-half hourly settled (aggregated) tariffs for domestic customers. The non-half hourly settled Domestic Unrestricted tariff has a single unit rate charge, the non-half hourly settled Domestic Two Rate tariff has two unit rates and the half hourly settled tariff has three unit rates applicable during three time bands specified by each DNO.

If the objective is to pay a single fixed amount to all eligible customers, one way to achieve this would be to create a new special domestic tariff (with its own line loss factor code – or LLFC). The payment could be applied as a credit against the fixed charge, either in one year or staggered over several years. This is option (g) in the previous section.

Under this approach, the maximum payment credit that can be applied in any one year (without the risk of negative charges) is the fixed charge in that year. For the year 2017/18, annual fixed charges for domestic customers range from £11.10 to £29.78 per MPAN.

Although it would be possible for the credit to be applied against unit rate charges (in p/kWh), it would be difficult to target a specific payment amount (in £) because the aggregate value of the credit would depend on consumption, and that can vary from customer to customer and from year to year.

3.1.3 Changes to DCUSA and DUoS charging methodologies

Three of the options set out earlier in this document involve changes to DCUSA. One involves a change to Schedule 16, which sets out the CDCM, the DUoS charging methodology applicable to domestic customers. The other two options involve changes to non-charging commercial sections of DCUSA.

Changes to DCUSA are made under the governance arrangements set out within DCUSA itself. Under these arrangements, provisions within DCUSA are categorised as “Part 1” or “Part 2” matters.[7]

Changes to Part 1 matters can only be made if approved by Ofgem, whereas changes to Part 2 matters can be decided by a vote of DCUSA parties. In practice, any change that has an impact on DUoS charges to customers is likely to be considered a Part 1 matter.

In making its decision on a change to a Part 1 Matter, Ofgem needs to have regard to the following:[8]

a) Its principal objectives and statutory duties[9]; and

[7] Please see section 1C, subsection 9 of DCUSA version 9.2 for definitions of Part 1 and Part 2 matters.

[8] Please see section 1C, subsection 13.9 of DCUSA version 9.2.

[9] These are set out in Sections 3A to 3D of the Electricity Act 1989.

b) Whether in its opinion the change better meets the DCUSA objectives.[10]

Based on previous decisions made by Ofgem in relation to changes to charging methodologies, it seems likely that a change proposal that seeks to introduce a special discounted tariff would need to be justified by reference to its benefits. In particular, given that discounted tariffs could lead to increased charges to all other customers (in the short term at least), the change proposal would need to demonstrate that the long-term benefits in terms of lower network investment outweighs the short-term increase in DUoS charges.

3.1.4 Regulatory barriers arising from distribution licence obligations

Design and implementation of any payment arrangements must pay close attention to the requirements the licence places on the distribution business:

a) To promote competition in supply and not to prevent or distort competition in distribution.
b) Not to discriminate unduly.
c) To comply with its approved charging methodologies, in particular the common distribution charging methodology (schedule 16 of DCUSA).
d) To comply with the contractual portions of DCUSA and other industry codes.
e) To follow specified governance procedures, often requiring Ofgem approval, when making changes to charging methodologies or to DCUSA.

Each of these requirements may act as a barrier. However, we focus on the first two requirements in the next sections. These seem the most likely to have an effect on the design of the payment arrangements, although the other requirements would also need to be complied with.

3.1.5 Impact on competition in supply

It is important that any payment scheme should be visibly even handed between different suppliers.

Any direct payments from a distribution business to customers would need to clearly originate from that distribution business, with no suggestion of any kind of any association with any electricity supply brands.

Irrespective of the payment option chosen, any customer-facing promotion of the scheme would be clear about the distribution/supply split and would not have any misleading effect on consumers or adverse impact on supply competition.

[10] The objectives in relation to non-charging matters are set out in Standard Licence Condition 22 of the electricity distribution licence. The objectives in relation to charging matters are set out in Standard Licence Condition 22A of the same licence.

3.1.6 Impact on licensed independent distribution network operators (IDNOs)

It is possible that some customers eligible for the scheme could have their connection managed by a licensed independent distribution network operator (IDNO), if the network reinforcement that might be avoided by a change in behaviour falls within the DNO's distribution system rather than the IDNO's system.

For example, if what is being avoided is reinforcement of a distribution substation, then the behaviour of customers supplied from that substation though a LV-boundary IDNO system is as important as the behaviour of customers supplied from that substation though the DNO system.

For all options which involve payments to suppliers, then the arrangements can be expanded to include IDNO-connected customers by paying the IDNO instead of the supplier, which is a natural extension since the IDNO rather than the supplier is liable to pay use of system charges in these circumstances. Our analysis of risks is on the basis that this expansion will have been done wherever appropriate.

Direct payments to customers are more difficult to deliver in the case of IDNO customers, since the only possible customer contacts are with the IDNO and the supplier so there is no clear way for the DNO to contact the customer. Our analysis of risks is on the basis that IDNO customers would fall outside the scope of the direct payment option.

3.1.7 Ofgem's targeted charging review and the principles related to "cost-reflective" and "cost-recovery" charging elements

Ofgem's recently announced targeted charging review may have an impact on one of the options discussed in this report (i.e. option g).[11] At this stage it is very early to predict potential impacts but SSEN are engaged in the review and further work by the SAVE project will take cognisance of any developments from this work stream.

As set out earlier, the discounted CDCM tariff approach has limitations on the amount of the payment in each year (i.e. without a risk of negative charges) because the fixed charge element of the domestic tariff is small relative to the total DUoS charge for a typical customer.

The consultation set out five options for setting "residual charges".[12] Two of these options involve recovering residual charges through the fixed charge element of the DUoS charge (options B and C in Ofgem's consultation). Under these options the fixed charge is likely to be higher than the current

[11] Ofgem, Targeted Charging Review: a consultation, March 2017.

[12] Ofgem has defined "residual charges" as those charges that recover DNOs' allowed revenues after taking account of recoveries from "forward-looking charges" that are set to reflect network users' impact on network costs.

CDCM fixed charge, which is based on an estimate of the costs associated with assets that are specific to the customer.

If one of these options is implemented, the amount of money that can be passed on to customers through credits against fixed charges would be higher than under the current CDCM methodology.

3.1.8 The proposed rollout of mandatory half hourly settlement for domestic customers.

Ofgem and the industry are currently progressing plans to roll out mandatory half hourly settlement to domestic customers. Domestic customers are currently settled on a non-half hourly basis using consumption profiles to determine consumption at different times of the day.

This would require domestic customers to be metered on a half hourly basis so that their consumption in each half hour can be recorded and used for settlement purposes.[13] Those customers that remain on meters that are not capable of recording half hourly consumption would most likely continue to be settled using profiled data.

Moving to half hourly settlement would expose suppliers to the cost of electricity consumed by domestic customers in each half hourly period. The “wholesale” cost of electricity varies according to the time of consumption, and the current CDCM includes a time of use (three rate) tariff for half hourly settled domestic customers.

The three rate domestic DUoS tariff could be used by DNOs to provide “signals” to customers to shift or reduce demand in ways that can reduce the need for network reinforcement. However, it would be possible to target customers in specific areas or those supplied from specific network infrastructure by creating more than one set of three rate tariffs within each distribution area.

It will eventually be up to suppliers to decide whether to offer time of use tariffs to domestic customers, and pass on any cost differentials to their customers.

3.1.9 Income tax and VAT

If the distribution business pays customers directly, then these payments are likely to fall out of the scope of VAT (since they are not part of a transaction for the supply of goods and services by the distributor) and might fall within the scope of income tax for recipients (since they could be seen as remuneration for following instructions).

If the payments are routed through the supplier instead, and provided that these payments are less than total electricity charges, then it is likely that the payments can be offset against other supplier

[13] Electricity suppliers are required by their licence to take all reasonable steps to roll out smart meters to all of their domestic and small business customers by the end of 2020.

charges and therefore that customers would also benefit from a reduction in VAT charges (so that each £20 paid by the distribution business would be worth £21 to the customer).

3.1.10 Summary of contractual, regulatory and administrative changes

Table 1 highlights some contractual, regulatory or administrative changes that would be needed to implement each option.

Table 1 Contractual, regulatory or administrative changes needed by each option

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Database of eligible customers	×	×	×	×	×	×	×
Individual customer interaction	×						
Supplier agreement and interaction outside DCUSA		×		×			
New billing/banking arrangements	×						
DCUSA contractual change			×		×		
DCUSA CDCM change						×	×
Ofgem approval needed to implement			×		×	×	×
Ofgem approval to treat payments as negative revenue	×	×	×	×	×		

3.2 Supplier Interaction

The effective implementation of DNO led ToU through all options except ‘option (a)’, above, would require suppliers to pass these price signals through to customers in their bills. Resultantly SAVE has explored the appetite of suppliers throughout the UK to adopt such tariff structures. SAVE reached out to suppliers through a letter introducing the project; its aims with regards informing ToU charging, and looking for guidance as to the potential impacts/considerations on suppliers both negative and positive should they adopt a DNO led pricing structure. This letter can be found in Appendix C. Suppliers were initially engaged on 3rd May 2017 using the industry forum Energy UK, (deemed a central, impartial voice across the energy industry). A week later e-mails were sent out individually to DCUSA contract managers (181 companies were contacted as per records on 3/5/17) at each supplier; by 1/6/17 this had warranted just two responses.

Whilst feedback from the projects initial interaction with suppliers was minimal and at this point cannot be taken as representative, key points to note around supplier uptake of flexible tariffs are noted in Table 2 below:

Table 2 Supplier Feedback

Topic	Large Supplier	Small Supplier
Attitude to domestic DSR	Customer feedback around ToU tariffs appears to be they're not interested, in general people want simpler billing as the current system alone is often seen as complex. Note that reacting to prices would need to be easy for the customer i.e. through facilitating technology.	A supportive attitude to DSR tariffs. Namely as a means for customers to reduce energy bills, through both benefiting those making necessary behavioral change and wider reduced network charges. Specifically with reference to benefits that should accrue to the fuel poor.
Vulnerable customers	Mention that those people likely to benefit the most commercially from tiered billing are those with facilitating technologies (PV, batteries etc.) this is likely to be those who are 'better off' and may be able to afford these technologies.	More skepticism towards CPP tariffs given potential knock-on effects for those most vulnerable within society who may be unable to shift their electricity consumption.
Impact of a supplier passing on DNO price signals	From a supply perspective a simplistic ToU that shifts load would be most feasible, geographical break-down has the potential to get very challenging. With regards to DNOs passing price signals through to suppliers via a change in DUoS they noted how the current RAG system doesn't work and isn't conveyed to consumers. With regards whether there would be a turning point in this it seemed unlikely given the complexity and that suppliers usually can just smooth pricing to smear risk to customers.	ToU network charges would complicate a supplier's tariff offering and suppliers would need to ensure the tariff was suitable in line with license obligations. Proposals made note that participation in such schemes should be voluntary to allow suppliers to assess whether customers would wish to participate and be comfortable that DNO's provide timely detail of any demand side requests.
Impact of	If this happened on a large scale there is	Noted importance that retailers are

DNO led DSR on suppliers	potential for imbalance of costs; however for larger suppliers this is likely diluted hence more able to manage risk. There would ultimately be a greater risk premium with un-predictable load which could affect costs. Would need to take care of customer confusion between DNO and supplier- this could be addressed through an aggregator model. Aggregator model also allows packaging of products not just at distribution level, hence maximising benefits.	aware what incentives a customer may be receiving to amend their consumption profiles given the industry's payment mechanisms This is likely to be specifically significant for suppliers with a regional focus given large concentrations of customers within defined geographical areas. Nonetheless there was no opposition to DNO's directly rewarding customers, so long as supplier interaction was maintained in a timely manor.
Other comments	Level of incentive would also be an important driver, wholesale makes up a far larger proportion of the customer bill, hence proportionally greater savings and hence appetite for customer change may be more significant here.	

The feedback received on SAVE, whilst mixed, shows a more forward looking outlook to domestic DSR from suppliers than that recorded by Customer Led Network Revolution (CLNR) in 2015 which noted "suppliers fed back that they would not wish to see the pass through of the DUoS (Red Amber Green) pricing to be mandated" (2015, p.6). As noted previously, whilst the sample of suppliers referenced should not be seen as representative, two hypotheses may be drawn from the above section.

1. Supplier attitudes towards ToU tariffs vary across different organisations.
2. As Smart Meters and the supporting infrastructure for ToU tariffs reaches higher penetrations of households, and the value from DSR initiatives becomes more accessible suppliers' attitudes need to be shifting to be more open and accommodating of ToU tariffs.

Despite a limited response to initial engagement with suppliers the SAVE Project will continue to look to gauge suppliers' viewpoints through the project's dissemination work. Initial thoughts to best achieve this are through more pro-active engagement at industry events and tailored meetings.

3.2.1 Case-study- Sunday peaks

The requirement for interaction between DNO's and electricity suppliers faces an evolving world. As the electricity spectrum becomes smarter and more complex integration across the industry will be crucial to effective accommodation of renewables, smart technologies and innovative management techniques such as DSR. The current level of interaction and viewpoints of suppliers on DNO led tariffs has been sought in section 3.2 above. Should this not be accounted and a market develop with minimal interaction between DNO's and suppliers the drivers of each party would likely conflict, economically resulting in a deadweight loss.

An interesting learning outcome from the initial analysis on SAVE shows that across the 4000 homes being monitored, across the four trial groups, each and every trial group (consisting of 1000 properties) shows winter peak demand for the week occurring on a Sunday, fractionally earlier than weekday evening peaks. Traditionally the peak would be expected to occur on a weekday, in the 1630-1930 period (based upon the red tariff highlighted in Figure 1). This is illustrated in Figure 9 below in which mean consumption (Wh) per 15 minute period for all days in January and February 2017 for the control group. March has been excluded to prevent confusion due to the clock change on Sunday 26th.

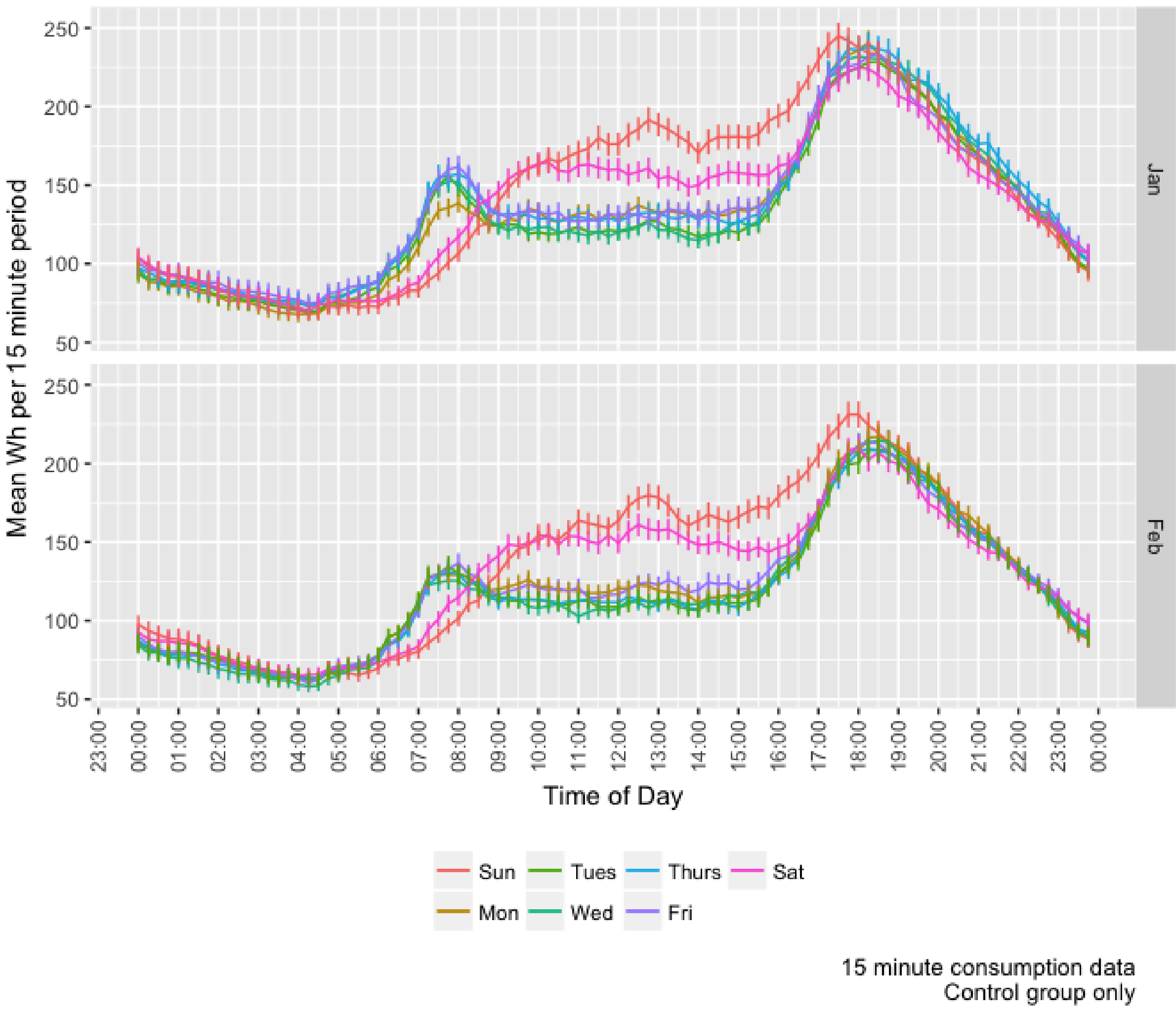


Figure 9 Time of Sunday Peak

The graph above shows how mean consumption is higher during the day at the weekends than during the week, and especially so on Sundays with no diminishing of the evening peak demand level. Indeed the Sunday early evening period sees higher consumption than on other days of the week. The only time of day when weekend consumption is lower than on weekdays is between 07:00 and 09:00 presumably reflecting differences in week-end breakfast habits.

The University of Southampton analysed this data in more depth to learn more. To carry out this analysis data from solely the control group (TG1) was used; due to the stratified random sampling approach used to recruit households and the subsequent random allocation to trial groups, the control group can be assumed to represent 'typical' winter customer behaviour in the Solent region of Hampshire, Isle of Wight, Southampton and Portsmouth. This also avoided any abnormalities in the data caused by trial interventions.

Figure 10 below uses this data to show the mean consumption (Wh) per day across all 15 minute observations for all days in January, February and March for the control group.

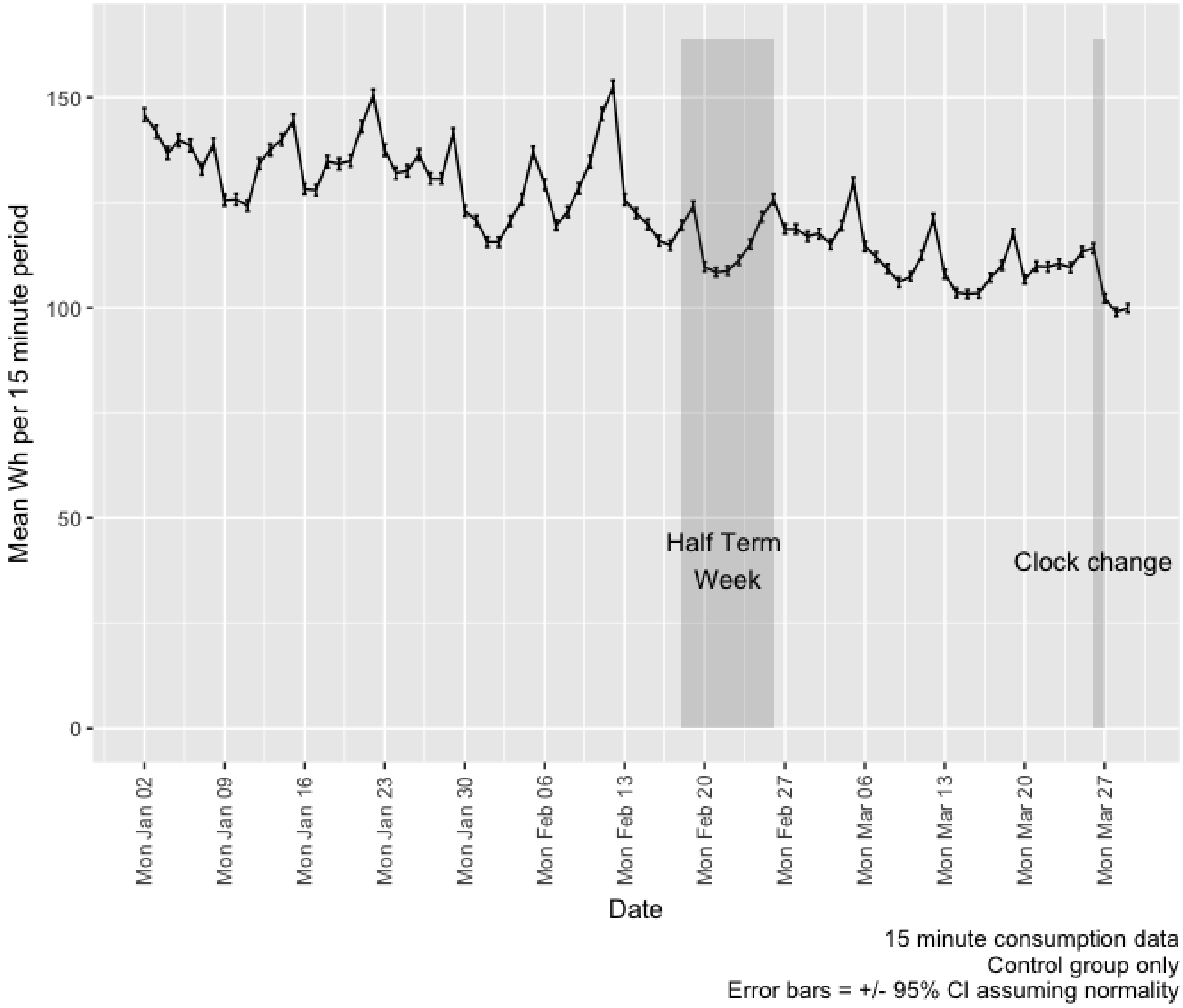


Figure 10 Weekly Consumption Jan-Mar

The chart clearly shows spikes in mean Wh consumed on Sundays with lower overall levels of consumption during weekdays. There is also some evidence of different consumption levels during half term indicating the potential effects of children and carers being at home during the day and/or absences due to holidays away from home (this is explored in more depth in Appendix D).

Whilst SAVE acknowledges this data does solely account for domestic customers and not for commercial customers whose contribution to network loading is likely to be higher during weekdays; it is highlighted that at lower voltage levels, perhaps where secondary substations and their feeders solely supply domestic residences, peak loading is likely to be at its maximum on a Sunday. Moving up the network to primary substation and higher voltage levels, greater diversity of customer types that are non-domestic will likely see more traditional weekday peak loading.

Given this learning, there are case-studies where DNO and supplier interests may already be in conflict. For example through the introduction of smarter tariffs is British Gas's HomeEnergy FreeTime tariffs (British Gas, 2017). This tariff looks to offer smart meter customers free electricity on Saturday or Sunday from 9am-5pm. Such tariffs mark a significant evolution in the way electricity is charged and how customers may use their electricity, with British Gas noting directly "you could do the washing, catch up on box sets, or mow the lawn - all for FREE"; could mark potential for significant network benefits if encouraged during off-peak times. Where network needs are not accurately represented or accounted for however, this has potential to make specific network situations markedly worse, in this instance by potentially increasing network demand on a Sunday where it is already apparent peak demand may occur on areas of the LV network.

It is suggested moving forwards that closer interaction, during tariff setting, between network operators and suppliers (and generators) is vital to maximise efficiencies in the usage of the UK's electricity resources and infrastructure.

4 Network pricing model

The Network Pricing Model (herein referred to as the Pricing Model) sits within a suite of purpose built data models, created for the SAVE project both by SSEN and project partners. The purpose of the Pricing Model is to create a probabilistic forecast of the benefits attributed to smart interventions over a period of 32 years.

The Pricing Model will take information from the Network Model (being developed with Project supplier EA Technology), and feed directly into the project's Network Investment Tool[14].

4.1 Overview

The Pricing Model estimates cost reductions that are likely to occur with the deployment of a smart solution on the Low Voltage network. It uses this information to further estimate cost savings at the different levels of a network, from Low Voltage (LV), to Extra-High Voltage (EHV).

The model does this by using net present value (NPV) techniques, to determine the current value of costs that are deferred or avoided, against the counterfactual costs if the interventions were not to take place.

[14] The Network Investment Tool is intended to be used by planners allowing them the accurate selection of "the most cost efficient methodology for managing a particular network constraint which is most effective for its connected customer types." (SAVE Project Bid 2013).

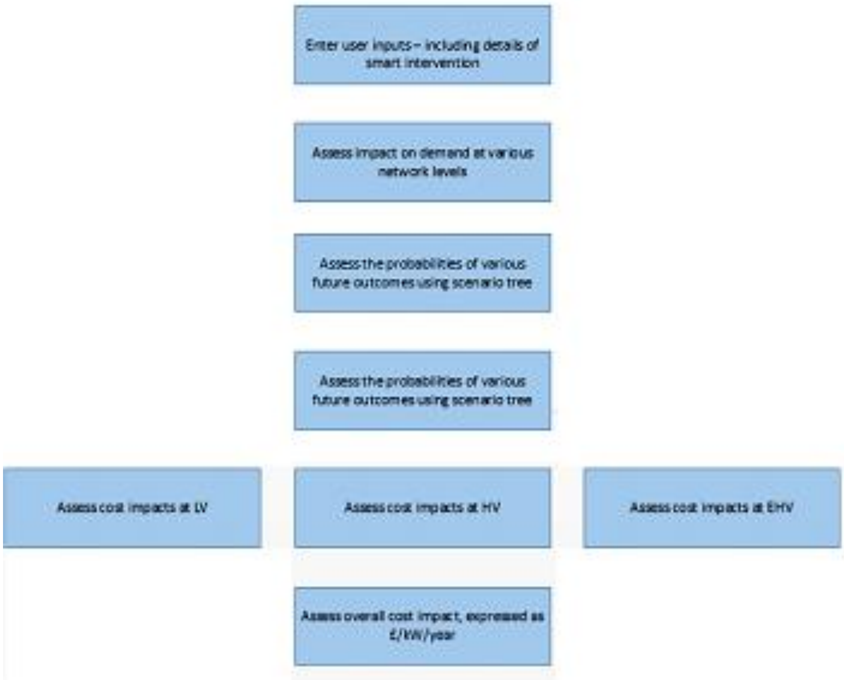


Figure 11 - Flow Chart of Network pricing model

Figure 11 shows the flow of information through the model, starting from the top. Uncertainty in the model is addressed by using a probabilistic approach. This is done with a 'scenario tree diagram' which allows the user to customise probabilities of outcomes at different times. Different paths have different probabilities, the results of which inform the level of incentive payment offered to customers that take part in each particular smart intervention.

In order to operate the model, the user will be required to enter a variety of inputs, as follows:

User Inputs	Description
Peak-time load reduction	How much power do we want to target as a reductic
Local Network costs associated with traditional reinforcement	32 year financial forecast for traditional reinforceme
Local Network costs associated with smart intervention	32 year financial forecast for smart intervention
Probability of outcomes	What is the probability of each path through the Sce
Network Groups	Select the substation
HV Feeder voltages	Select the feeder

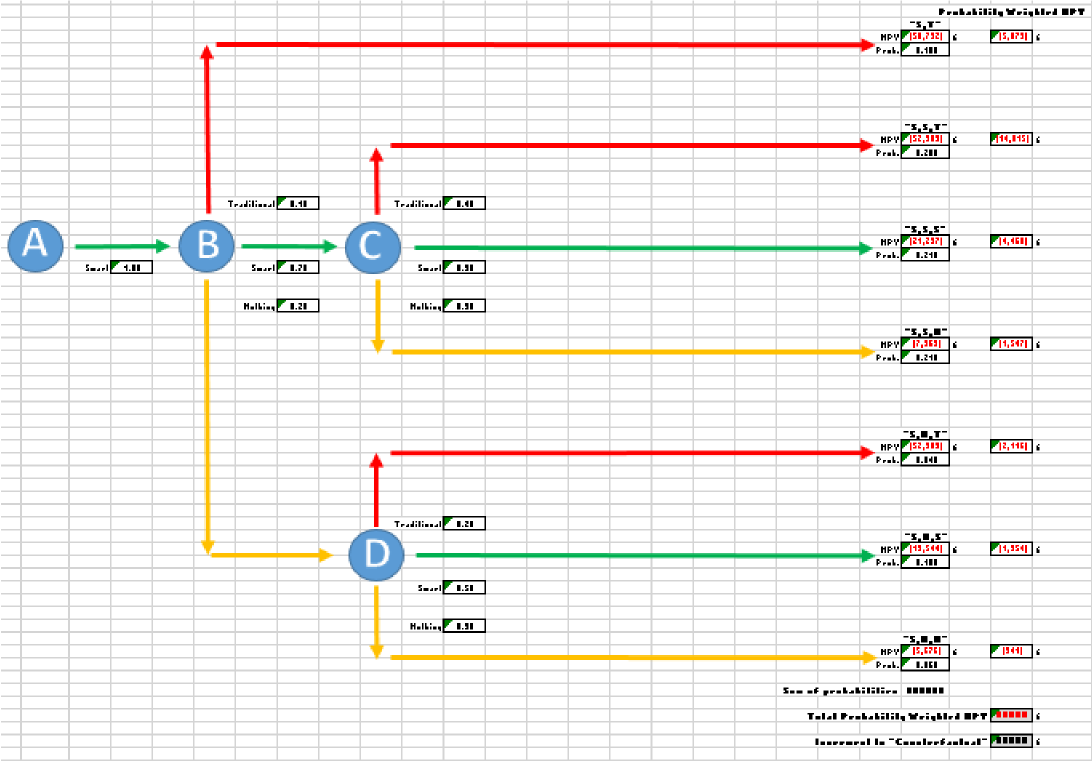


Figure 12 - Scenario Tree Diagram

Figure 12 shows how the scenario tree diagram is laid out. Given the purpose of the model is to give a smart alternative to traditional reinforcement, an assumption is made that at point A, there will always be a smart intervention. At points B, C and D, there is a choice between continuing with the smart intervention (S), doing nothing (N), and traditional reinforcement (T). This creates 7 potential pathways, with costs associated with them running down the right hand side. Each choice has a probability, which is can be input and amended by the user within Table 3 below.

Table 3 Probability Forecast

	Prob. "T"	Prob. "N"	Prob. "S"	**Sum** (must equal 1)
Node A	0.0	0.0	1.0	1
Node B	0.1	0.2	0.7	1
Node C	0.4	0.3	0.3	1
Node D	0.2	0.3	0.5	1

The costs are weighted against the probabilities and averaged, to give the predicted money saved on deferral/avoidance of immediate traditional reinforcement. The final output will then give a £ per kW saving, with optionality built in, based upon the smart solution selected; allowing a network planner to visualise the cost savings/loss from deploying a given smart solution over traditional reinforcement. If the final output is showing as £0 or below, then the smart intervention is too expensive for that network area, and a different intervention should be tried, or traditional reinforcement should be considered.

The purpose of the model is to provide a probabilistic forecast, accounting for optionality value and hence allowing for flexibility in network management given potential uncertainty in future network loading. The probabilistic value should fall somewhere between the smart intervention cost, and the traditional reinforcement cost, depending on the levels of probability that have been set.

Within SAVE group 3 trials (data informed engagement + price signals) this model also provides an indicator as to the maximum amount of price incentive that a DNO may be willing to offer its customers to achieve a pre-determined level of load-reduction. This could be calculated based upon the difference in cost between traditional reinforcement and data informed engagement alone. An example of this is given in Appendix B.

The final output then gives an incentive price per kW that can be offered to participants in a smart intervention program, or/and that can be fed back into the business as savings from traditional reinforcement.

4.2 Network Investment Tool

The projects current view is that a singular Network Model (being developed by EA Technology), will provide multiple smart network management solutions (see SDRC 7.1) to be fed into multiple unilateral Pricing Models (shown in Figure 13 below as ‘Assessment of Network Performance). For example you may have one Pricing Model for LED lighting, one model for price signals, and one for a battery storage solution. The outputs from the Pricing Models will be collated into the Network Investment Tool to give a prospective Network Planner a selection of possible options to take forwards. Further improvements could be made by allowing a mixture of different smart solutions, for example, the roll out of LED lightbulbs to domestic customers, but also implementing a battery storage solution. How this might be implemented is currently under discussion.

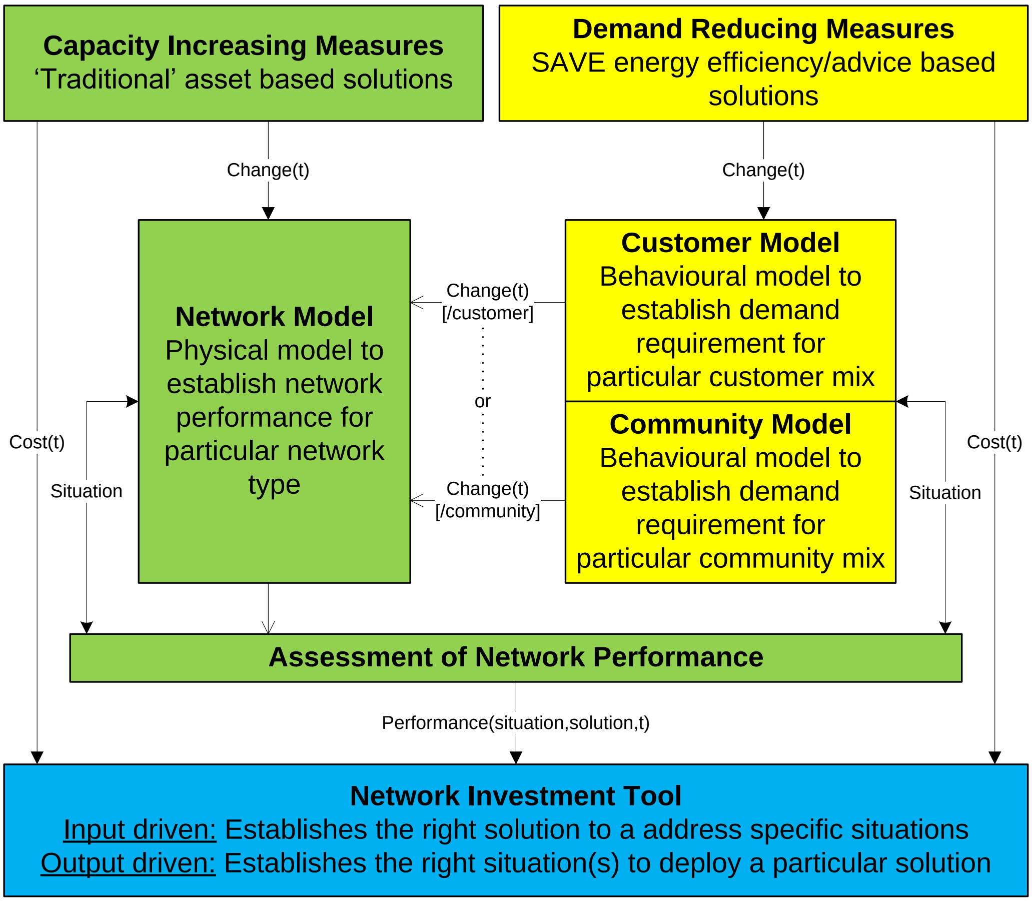


Figure 13 - Data Flow to Network Investment Tool

5 Live Trials

This section details the trials that have, at the time of reporting, been carried out on SAVE and their outcomes based on analysis to date, in addition to interventions planned for the future. This will provide insight into the mechanisms (namely focusing on price signals) that a DNO might adopt in order to procure domestic demand response, the variables to be considered in such network management techniques and indications of initial levels of load-reduction that may be expected; specifically focusing on price signalling trials.[15] Whilst the upper boundary of incentive level for the price signalling trials can be determined by the Pricing Model (based on break-even with traditional reinforcement); trials themselves may explore differing levels of payment within this pre-defined upper bound for payment in order to best understand consumer's price sensitivity.

[15] Note the trials explored within this section focus solely on those with household level monitoring, the Community Energy Coaching trials are not discussed within this report.

The level of load-reduction that can be achieved and the costs of delivering these reductions through the SAVE methods can be fed directly into the Network Investment Tool to determine whether these methods are viable alternatives to traditional reinforcement.

5.1 Trial Period 1 Planning

As outlined within June 2016's updated SAVE bid document (Appendix 8 of Change Request 2), Trial Period 1 (TP1) ran from 1 January to 31 March 2017. As discussed within previous reporting periods, trial periods were amended in order to best maximise project learning, through both the addition of a third trial period and to accommodate the material change in circumstance as a result of initial equipment failures, outlined in Change Request 2.[16]

The interventions delivered activities designed to encourage householders to reduce consumption during peak hours, by changing usage behaviour or by installing specific energy efficient technology. Each of the trial groups was designed to test the efficacy of outreach activity in generating household interest in demand reduction measures and energy efficiency schemes.

In total, the trial had four groups: one control and three treatment groups to which households from the stratified random sample recruited onto the project, were randomly allocated (for more detail see SDRC 5.1). The original trial design was to have one treatment group focussed on purchasing and installing LEDs and two consumer engagement groups (one with price signalling and one without). Trial planning looked to mirror the media sent to both groups 3 and 4 with the single difference that the event day at the end of the trial period would offer no-incentive to group 4 participants, whilst group 3 participants would receive a £10 voucher for achieving a 10% reduction in consumption across the event. However, upon initial analysis the project team discovered a processing error in the participant lists used for online communication. This however has allowed the project to trial a range of alternate and unanticipated hypotheses as noted below[17]. For the purposes of trial period 1 this resulted in the following groups receiving interventions as below:

- Group 1: Control group
- Group 2: LED trial through postal communications and consumer engagement through online communications including event day messages (but without price signalling)
- Group 3: Consumer engagement through both online and postal communications and price signalling including event day messages
- Group 4: Consumer engagement through postal communications only

[16] TP1 is from January to March 2017, TP2 is from October 2017 to March 2018 and TP3 is from October to December 2018.

[17] This processing error had no effect on the control group who remain neutral.

These groups use a slightly different numbering system than was originally laid out in the bid proposal. However, that numbering system did not include a numerical label for a control group, and thus was the cause for error (as described above). In order to avoid similar mistakes in the future, the project team has introduced the numbering system above, starting with Group 1 as the control group. This numbering system is used throughout the report and will be used in all future reports in order to mitigate against any risk of such error occurring in future trial periods. This numbering system has also been hardcoded into the participant ID used by BMG and Navetas.

Whilst the project cannot cleanly isolate the impact of the price signal for the TP1 event day, SSEN and SAVE project partners are confident this can be addressed in Trial Period 2 (TP2) with no implications to the outputs of the network investment tool at the close of the project. However, the changes to the TP1 messaging have allowed the project to identify a range of different outcomes, arguably acting as a greater building block for TP2, which will provide ample opportunities to test direct comparison between data-informed messaging and price signals. Given the minimal impact of LED trials in group 2 (see section 5.2.1 for more details), this sample group can largely be assumed neutral from this form of engagement; thus SAVE can gain value from this group by understanding the difference between customers receiving just online communication (group 2), just postal communication (group 4) and both e-mail and postal communication (group 3). This not only provides significant insight into one of the projects key learning outcomes “to identify the most effective channels to engage with different types of customers”(SAVE Project Bid, 2013) but moving forward, this will allow the project to ensure it is contacting customers in the most cost-effective means. This will be further tested with the engagement groups in TP2 (see section 5.3.2). In TP2, group 2 will only receive LED related messaging, whilst groups 3 and 4 will provide a direct comparison of the impact messaging with and without price signals.

5.1.1 LED Trial

In the first trial period, the LED trial group (group 2) was offered discounted LED products for sale via a voucher (sent by post) that linked to a project specific retail website (http://saveled.co.uk). This engagement aimed to promote LEDs as an easy way to reduce electricity use and explain the benefits of LED lighting technologies.

Following robust procurement processes to identify the optimal supplier of LED lighting for the projects needs, the project team elected to partner with RS Components. RS Components recommended six different bulb types and offered a 20% discount to SAVE trial participants.

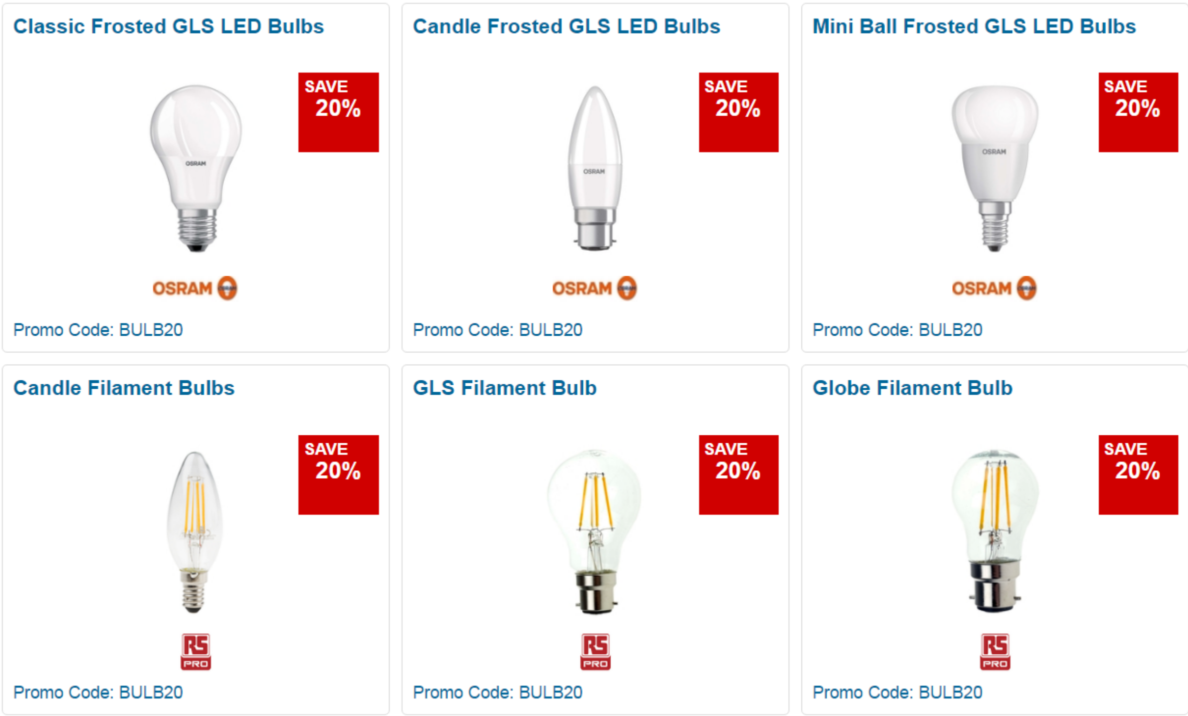


Figure 14 LED bulbs available on saveled.co.uk

Customers were directed to the saveled.co.uk site via two postal mailings developed by project partner DNV GL and Behaviour Change. The first mailing was a four page A6 booklet that explained the advantages of LED bulbs over traditional technologies. The second postal mailer was a post card with a reminder of the discounted offer and a call to action.

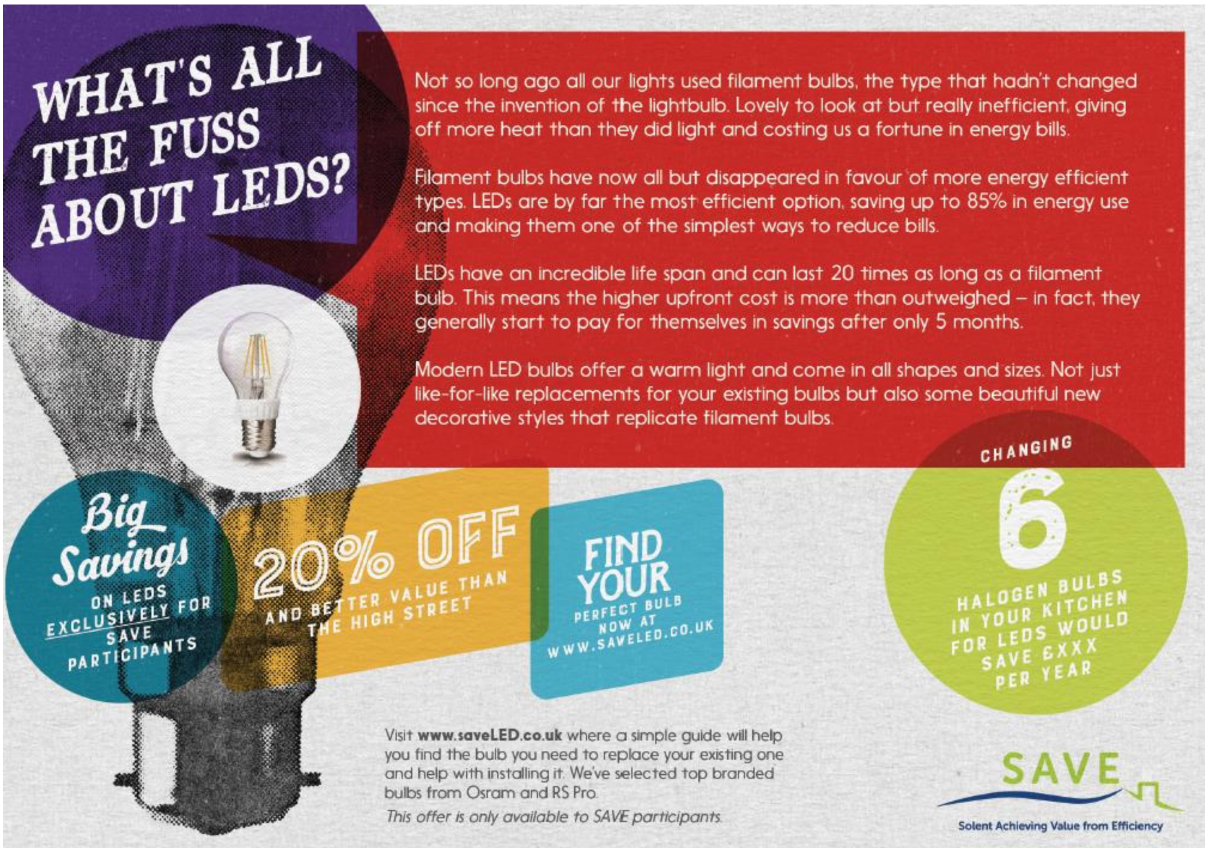


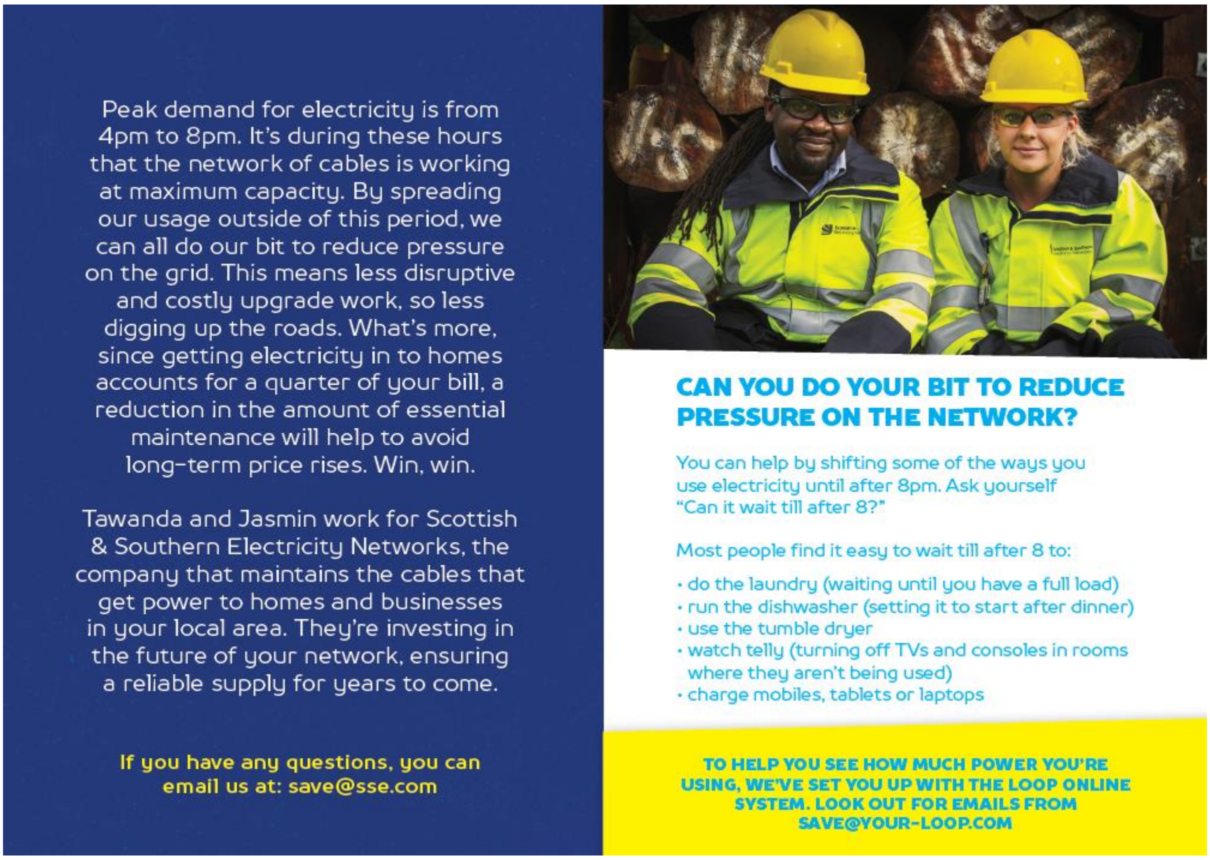
Figure 15: Interior of initial LED mailer

5.1.2 Consumer Engagement

The trial also explored how consumer engagement techniques can be used to shift electrical consumption out of the peak period. TP1 focused on general education around the peak period and energy efficiency. It introduced the idea of a peak period of 4 to 8 to consumers and explained why the electricity network is sometimes stressed at this time.

The engagement campaign started with an introductory booklet of information that asked consumers to “help keep the power flowing”. The booklet introduced two SSEN employees and explained how they are working hard to keep consumers power flowing. It also explained what SSEN does and the basics of how electricity gets to households. The booklet asked, “can it wait ‘till after eight?” and provided tips on simple ways to reduce pressure on the network.

Figure 16: Interior page of initial engagement booklet



Over the next nine weeks, this booklet was followed up with one general knowledge postcard and five postcards with specific asks, such as:

- Waiting until after 8pm to do the washing or running it only with full loads
- Waiting until after 8pm to charge mobiles and tablets
- Waiting until after 8pm to use the tumble dryer
- Waiting until after 8pm to run the dishwasher or using its timer/delay function
- Waiting until after 8pm to watch television or turn the television off in rooms that are not being used

Figure 17 Sample Postcard (Front and Back)

All three treatment groups received some sort of consumer engagement messaging:

- Group 2 received emails and web portal notifications
- Group 3 (data informed engagement and price signals) received emails, web portal notifications and postal mailings
- Group 4 (data informed engagement) received postal mailings

Although the delivery mechanism differed, the content was identical across all platforms.

5.1.3 Price Signalling and Event Day

In addition to the consumer engagement messaging, two groups (Group 2 and Group 3) also received notifications about an 'event day' through emails and portal notification. This was designed to test consumers' ability to reduce their consumption on a specific (singular) day when the network was experiencing higher than usual stress. In the real world, this may be due to equipment failures, exceptionally high electricity use, maintenance work / taking equipment offline, weather, etc. The team chose Wednesday, 15 March as the event day to test a 'regular' weekday. Group 2 was asked to reduce their load by 10% during the peak period (when compared to the previous Wednesdays) without any incentive while group 3 was offered a £10 high street voucher if they met the same ask.

The price levels in TP1 were determined based upon analysis put together in the SAVE business case (Appendix N of full submission) and ensuring any level was deemed market competitive (this is important to consider for aggregator models of domestic DSR). Given the 'event day' structure of the trials present clear similarities to National Grid's triads; commercial analysis was performed between average household demand and £/kW payment levels for triads, the outcome of which suggested a £10 incentive would require at least a 7% load-reduction from each household to be cost-competitive. Accounting behavioural economics in this equation it was determined that consumer responsiveness would benefit from a more relatable, less precise figure of load-reduction and hence this was rounded to 10% for £10.

Below is an example of the email message group 2 received two days before the event day. Group 3 received a similar email but with a note about the incentive.

Figure 18: Event day messaging

5.2 Trial Outcomes

5.2.1 LED Trial

As described earlier, mailers directed the LED trial participants to http://saveled.co.uk, which was set up by RS Components. This website allowed participants to purchase discounted LEDs from a selection of common bulb types. Over the length of the trial, the website had 225 page views. This represents about 19% of the participants who received the leaflet/postcard in the post.[18] Of these visits, 69% progressed to a product page while 31% left the website before viewing a product. Of those that visited the site, 5 participants made a purchase. This translates to 0.4% of participant take up of the discounted LED offer.

This take up is not entirely unexpected, as direct mail has average response rates of somewhere between 1 and 3.7% depending on type of mailing list and product (Haskel, 2015). The web conversion rate of 19% is higher than expected, although the actual buy rate is lower than expected.

5.2.2 Consumer Engagement

Analysis of the consumer engagement activities is ongoing. Due to the very large amount of data collected across the four groups, analysis is a time-consuming process. The original metering equipment collected 30-minute data, which would have resulted in a much smaller quantity of data to analyse. The replacement Navetas Loop kit collects 15 minute Wh (energy consumption) data and 10 second W (power) data. This resulted in c. 31.5 million Wh observations and c. 2.835 billion W observations across the trial period. Since the original project bid data analysis resourcing had not anticipated the availability of the extremely large W (power) dataset, the current report focuses only on the Wh (consumption) data. Similar analysis of the W (power) data will be reported at the end of the project SDRCs (8).

5.2.3 Price Signalling and Event Day

In-line with the commercial focus of this report, the section below presents preliminary analysis of the effect of the event day intervention (as implemented) on evening peak electricity consumption during TP1. As noted above given the actual implementation of the interventions this means comparing electricity consumption between[19]:

- Group 1: control group
- Group 2: LED trial through postal communications and consumer engagement through online communications including event day messages (but without price signalling)
- Group 3: Consumer engagement through both online and postal communications and price signalling including event day messages

This means that we do not have a clean distinction between Groups 2 and 3 which can be used to test the effect of a pure price incentive since there are other differences between these groups. However,

[18] 1,137 household received mailers about the benefits of LED lighting.

[19] Group 4 did not receive any event day notifications as no event day notifications were sent by post.

Group 3 should show the largest reduction compared to the control group (Group 1) since Group 3 received all possible messaging. It follows that Group 2 should show a reduced effect as they did not receive the financial incentive or the ‘shift/reduce’ postal materials. Because the postal LED communication elicited a low buy rate as seen in section 5.2.1, it is assumed that it had minimal interaction with the other messages for Group 2.

In general, there are two ways to conduct such analysis:

- In the case of a natural experiment where interventions may occur at any time or in the absence of a control group it is usual to calculate the difference in the energy consumed between the event period and a corresponding historical period (for example: Allcott and Rogers 2014; Carroll, Lyons, and Denny 2014). The magnitude of this difference is then compared for the different intervention groups. Given seasonal trends in TP1[20], this would need to 'correct' for the overall downward trend in household electricity consumption over the period.
- In the case where the intervention occurs at a specific time (as here) and where a randomised control trial (RCT) design is used (as here) there is no need to calculate a difference between 'before' and 'during' the intervention. Instead any difference in consumption between the control and intervention groups is assumed to be a result of the intervention alone (Frederiks et al. 2016). Since participants in the study likely experienced the same environmental conditions on the same day, analysis does not need to correct for any differences in environmental conditions such as temperature or solar irradiance.

Given the RCT design of the SAVE trials, the analysis follows the second approach. The University of Southampton have calculated summaries for relevant periods on the event day (Wed 15 Mar 2017) as well as the day before/after to assess the extent to which demand may have been shifted from the event day peak period to outside of it, as suggested by previous studies (Herter, McAuliffe, and Rosenfeld 2007; Schofield 2015).. The analysis uses mean Wh calculated over the 15 minute observations for the relevant time periods as the key indicator.

Note that due to the randomised control trial design of the study, it is not necessary to control for other potential confounding characteristics of the households in each trial group. However in the analysis below the project includes a small selection of household attributes to understand if certain characteristics are associated with a stronger reduction effect.

The analysis team removed all 0 Wh observations (i.e. actual readings of 0 Wh as opposed to missing readings) before analysis and Table 4 shows the number of observations and households used.

[20] As spring approaches, days get longer and warmer necessitating less energy consumption.

Table 4: Number of observations and clamps on the event day and each day before/after

Group	Day	No. observations	No. households
Group 1: Control	Tue 14 Mar 2017	91,575	968
Group 1: Control	Wed 15 Mar 2017	91,612	967
Group 1: Control	Thu 16 Mar 2017	91,435	965
Group 2	Tue 14 Mar 2017	97,124	1018
Group 2	Wed 15 Mar 2017	97,132	1018
Group 2	Thu 16 Mar 2017	96,950	1017
Group 3	Tue 14 Mar 2017	83,794	877
Group 3	Wed 15 Mar 2017	83,799	877
Group 3	**Thu 16 Mar 2017**	**83,670**	877

Sections 5.2.3.1 and 5.2.3.2 below discuss two forms of analysis used on the project, descriptive analysis and regression analysis.

5.2.3.1 Descriptive Analysis

This section reports descriptive analysis of the difference in consumption between the trial groups for the event day. Overall, on the event day:

- Group 2 mean Wh for the 16:00 - 20:00 period was 96.43% of the Group 1 (Control) mean - a reduction of 3.57 %
- Group 3 mean Wh for the 16:00 - 20:00 period was 96.67% of the Group 1 (Control) mean - a reduction of 3.33 %

These overall results suggest that neither intervention was particularly successful in reducing demand as these reductions are lower than anticipated. However, in contrast to most previous studies of this kind, the sample used is representative of the customer population from which it is drawn; a potential contributor to a lower response than would be found in studies of self-selecting volunteers who are more likely to be highly motivated and engaged (Abrahamse et al. 2005).

Figure 19 below shows the mean consumption per 15 minute period for the event day and the day before/after to provide a visual analysis of any shifting of consumption to periods outside the event day peak period and/or to the previous or subsequent day. The chart suggests that Group 3 used slightly more electricity during the peak period on the day before the event compared to Group 1 (the control) and Group 2. Both Groups 2 and 3 appear to have used slightly less electricity during the peak period on the event day itself with some suggestion that they may have used slightly more in the morning period around 08:00 and slightly more in the period just after the event day peak period and also on the day after.

Figure 20 repeats this analysis but includes 95% confidence intervals and indicates the likelihood that any visible differences between the means are statistically significant. If the 95% confidence intervals overlap then there is unlikely to be a statistically significant difference. The differences visible in the first chart are almost completely obscured by the over-lapping confidence intervals and therefore suggest that the project is unlikely to see statistically significant differences in a more detailed analysis.

Figure 19: Temporal profiles of consumption around the event day

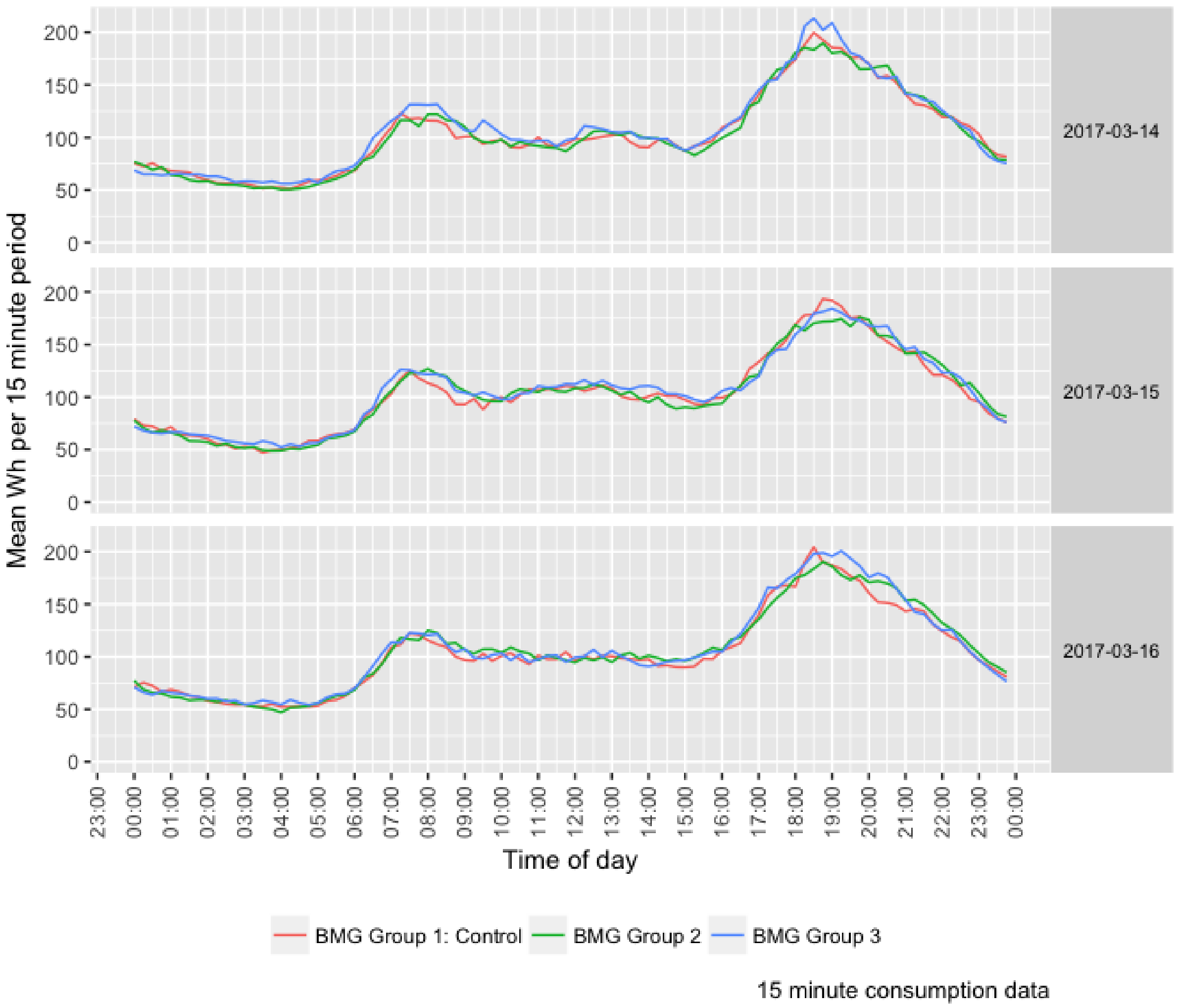
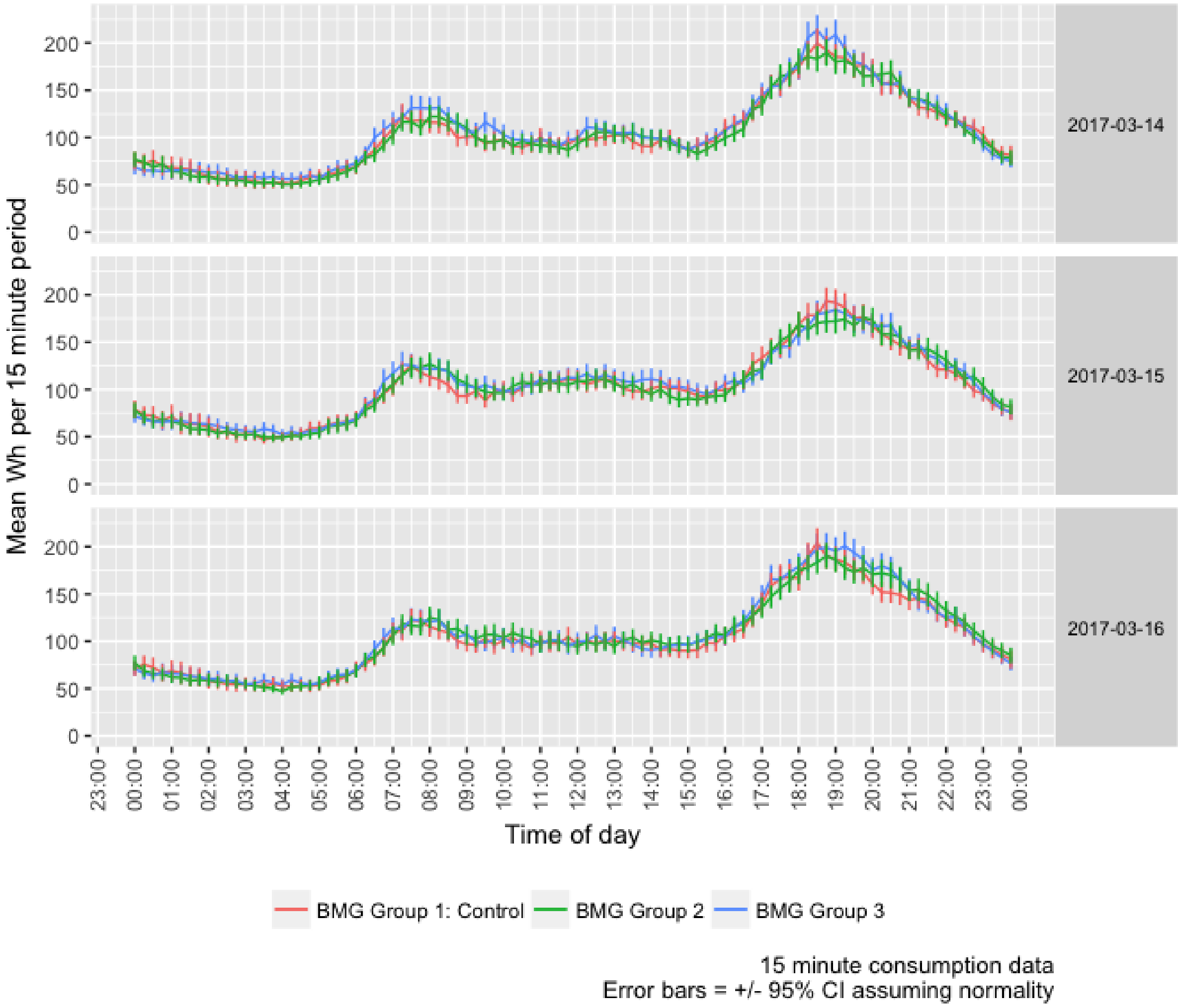
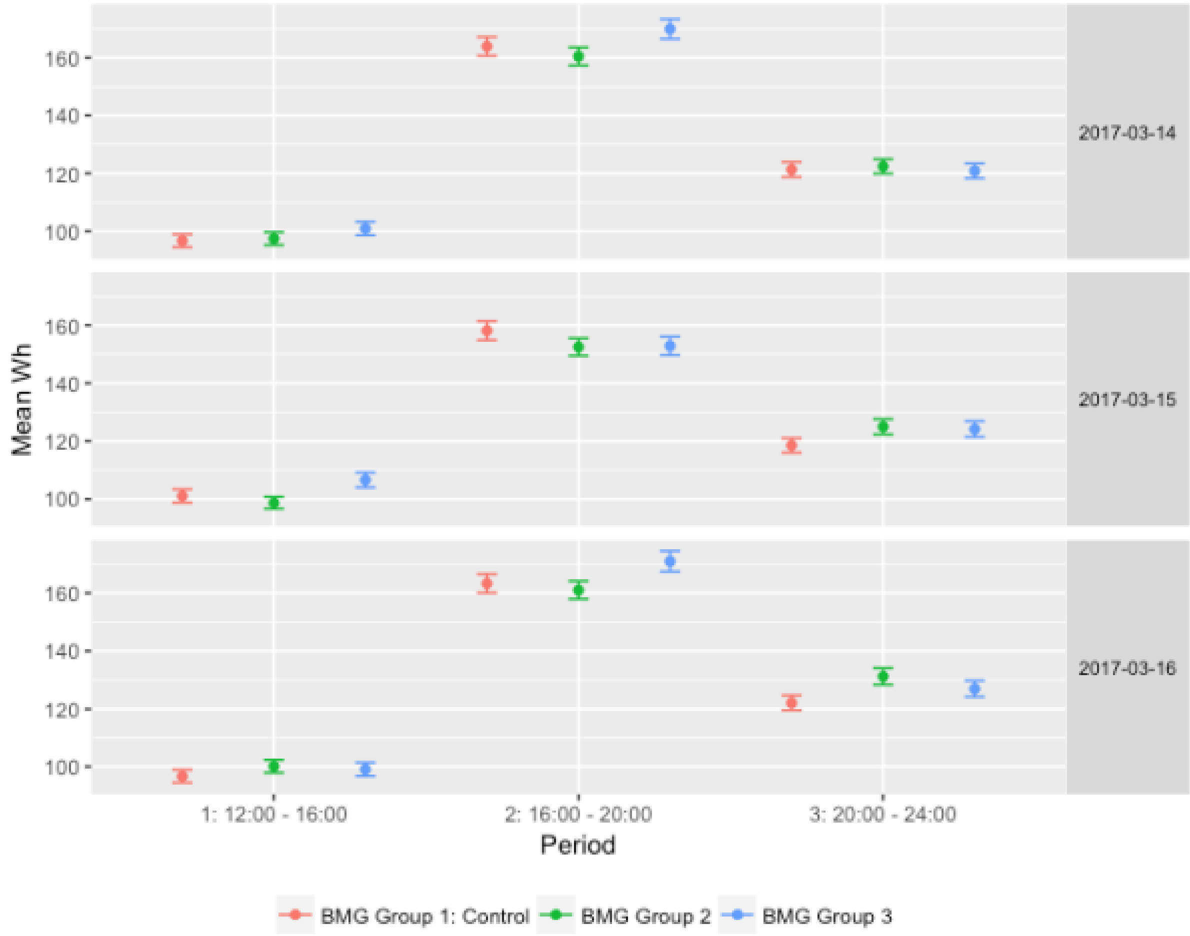


Figure 20: Temporal profiles of consumption around the event day (with 95% CI)



The set of charts below in Figure 21 show the overall mean for the 16:00 - 20:00 periods of each day compared to the 4 hours before/after and as above, the 95% confidence intervals give an indication of the statistical significance of any numerical difference.

Figure 21: Mean 15 minute Wh per period during pre/event/post-event day



15 minute consumption data
= mean of all 15 min Wh values per household in the period (Error bars = 95% CI assuming normality)

The charts suggest that:

- On the day preceding the event day: Group 3 appeared to use more than the other groups during the evening peak period which would be the case if consumption had been shifted to this day from the event day;
- On the day of the event: Groups 2 and 3 used slightly less than the Control group during the targeted peak period but only Group 3 used more in the period just prior to the peak period. Both Groups 2 and 3 appeared to use slightly more than the Control in the period just after the peak;
- On the day after the event: Group 3 again used slightly more than the other two groups during the peak period which would be the case if consumption has been shifted to this period from the day before.

However, the extent to which the 95% confidence intervals overlap suggest that few of these effects will prove to be statistically significant. We test this in the next section using a standard regression modelling approach.

5.2.3.2 Regression Analysis

This section reports the results of a regression based analysis which assesses the factors associated with mean consumption in the relevant periods and shows the net effect of the interventions applied to each group.

The regression approach used requires that the dependent variable (mean Wh) is normally distributed. However, this was not the case. Taking the mean Wh over a period of time (as here) only has a small 'normalising' affect and so the regression models use an additional log(mean Wh) transformation prior to model estimation to provide a suitable normal distribution (see histogram in Figure 22 below). This means that coefficients reported in subsequent tables and charts represent the effect of co-variates (such as group membership) on log(Wh) and not Wh. This does not affect their interpretation but it does mean that they need to be exponentiated to infer Wh differences.

As above, the analysis team separated the models into an assessment of differences between the intervention and control groups as follows:

- Differences in the period 12:00 - 16:00 on the event day. The hypothesis is that the intervention groups would use more electricity in this period to avoid the peak period.
- Differences in the period 16:00 - 20:00 on the event day. The hypothesis is that the intervention groups would use less electricity in this period (as instructed).
- Differences in the period 20:00 - 23:00 on the event day. The hypothesis is that the intervention groups would use more electricity in this period to avoid the peak period.

For the purposes of this report section 5.2.3.2.1 and 5.2.3.2.2 below will report solely on the impact during the event period (16:00-20:00). Analysis of those time-periods both before and after the event day can be found in Appendix E.

For each time period there are three models:

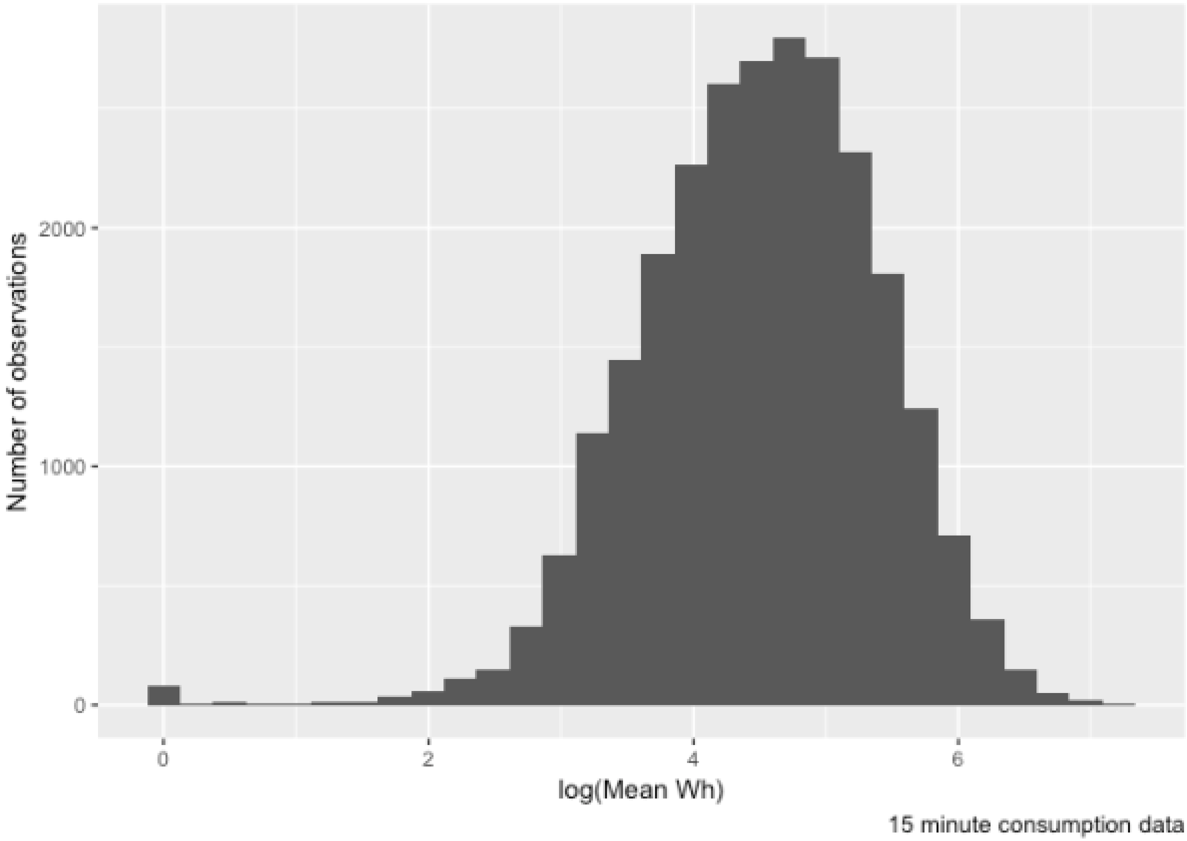
- Model 1: A basic regression model testing only membership of the trial groups. This tests the extent to which experiencing the interventions is associated with lower or higher consumption compared to the control group.
- Model 2: A model which also tests the effect of the Group 2 or Group 3 household having opened the event day email (the communication the project can detect interaction with). Clearly, this would be an indicator of more active reception of the event day message and is the only system-based data we have on the receipt of the event day notification.
- Model 3: A model which also tests for:
    - The effects of the presence of children (as a predicted constraint on evening peak consumption reduction).
    - The effects of employment status (full time employed vs retired vs 'other').

- The effects of pro-environmental attitudes as reported by the household response person. This takes the form of a mean of the Likert score[21] responses across a battery of 6 'environmental attitudes' questions. A high score represents reporting stronger pro-environmental attitudes.

To test if the presence of children increases or decreases the effect of the intervention, Model 3 also includes the presence of children as an interaction with trial group membership. This form of analysis could be extended in later work to examine the joint effects of other household attributes and interventions. Note also that model 3 has substantially lower numbers of households compared to the other models as the surveys that collect this information are still in progress. This is likely to lead to larger confidence intervals for the coefficient estimates.

To date the team has not conducted regression analysis for the previous and subsequent days.

Figure 22: Histogram of log transformed mean Wh indicating normality of distribution



[21] The Likert Scale is used to measure attitudes to a given topic. It uses fixed choice responses to measure agreement or disagreement in a linear fashion. More information available at https://www.simplypsychology.org/likert-scale.html.

5.2.3.2.1 Event day full peak period results (16:00 – 20:00)

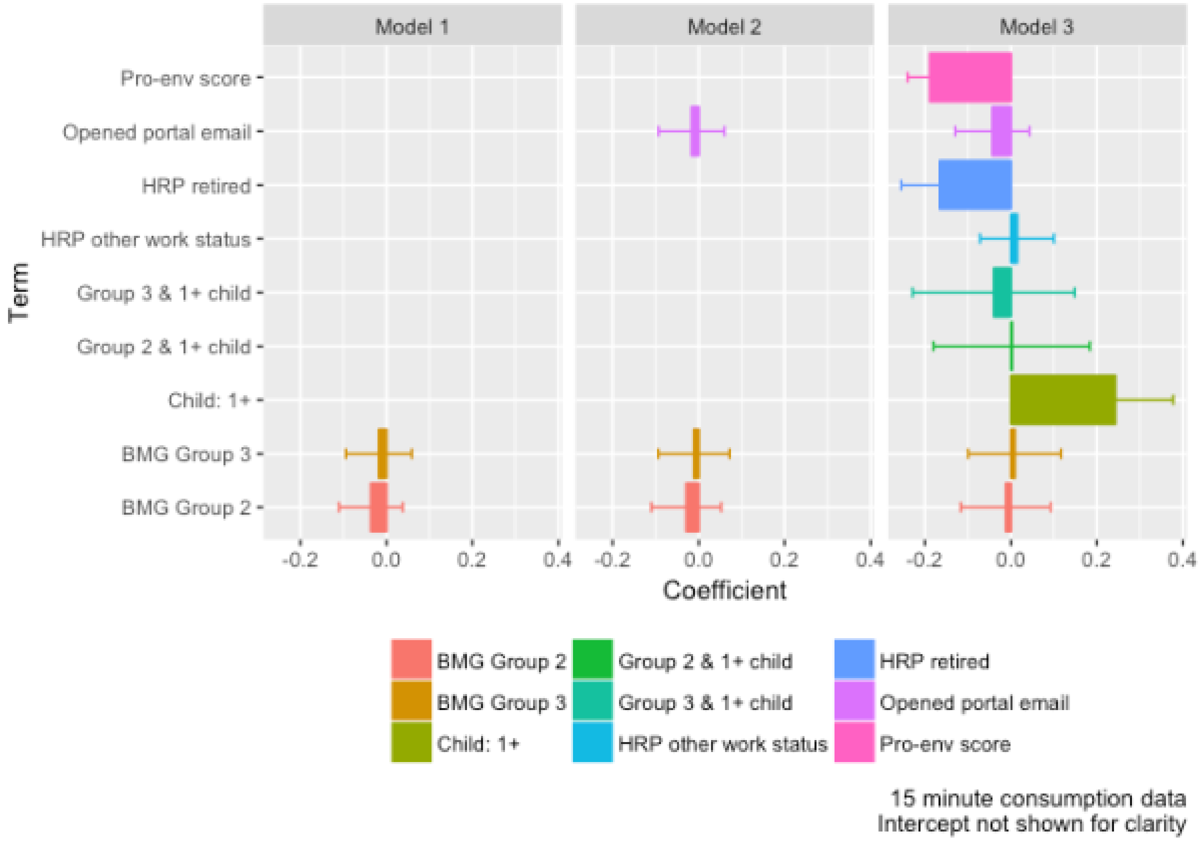
Table 5 below reports the results of the three regression models for the event day peak period 18:00 – 20:00. The results are also visualised in the Figure 23: Event day peak period regression results (16:00 – 20:00) although the intercept (constant) is omitted for clarity. The coefficients represent the net statistical effect of the variable on log(meanWh) in that period. Strictly speaking these are correlation effects but the RCT nature of the study design means that can be taken as causal effects.

As a guide, any co-efficient that has one or more * in the table is statistically significant at the 95% level or greater. Similarly, if the 95% confidence interval (CI) for the coefficient shown in the chart does not include 0 then the effect is statistically significant at the 95% level. Note that the 95% CIs referred to in the model results tables and charts are not subject to the same potential invalidity as those used in the descriptive analysis above.

Table 5: Event day peak period regression model results (16:00 – 20:00)

	Dependent variable:		
	Log(Mean Wh)		
	Model 1	Model 2	Model 3
	(1)	(2)	(3)
Group 2	-0.036 (-0.110, 0.037)	-0.029 (-0.110, 0.052)	-0.012 (-0.117, 0.093)
Group 3	-0.018 (-0.094, 0.059)	-0.011 (-0.094, 0.072)	0.009 (-0.099, 0.117)
Email: Not applicable			
Email: Opened		-0.017 (-0.093, 0.060)	-0.043 (-0.129, 0.043)
1+ child			0.243*** (0.109, 0.378)
HRP Retired			-0.165*** (-0.254, -0.076)
HRP: Other work status			0.015 (-0.072, 0.101)
Pro-environment score			-0.188*** (-0.240, -0.136)
Group 2 & 1+ child			0.002 (-0.179, 0.184)
Group 3 & 1+ child			-0.040 (-0.228, 0.149)
Constant	4.759*** (4.706, 4.812)	4.759*** (4.706, 4.812)	5.283*** (5.114, 5.453)
Observations	2,851	2,851	1,998
R^2	0.0003	0.0004	0.068
Adjusted R^2	-0.0004	-0.001	0.064
Residual Std. Error	0.836 (df = 2848)	0.836 (df = 2847)	0.784 (df = 1988)
F Statistic	0.465 (df = 2; 2848)	0.370 (df = 3; 2847)	16.218*** (df = 9; 1988)
Note:	*p<0.05;* ***p<0.01;*** p<0.001 95% confidence intervals for estimates in parentheses		

Figure 23: Event day peak period regression results (16:00 – 20:00)



Overall the results show that the interventions had a small effect in the direction expected. Groups 2 and 3 had lower consumption during the period than the Control group in both models 1 and 2 and those who had opened the email also used less. Interestingly the effect appears to be slightly larger for Group 2 (who did not receive the price incentive) but the results were not statistically significant in either case.

Those with more pro-environmental attitudes used less overall whilst those with children used more overall and both these effects were statistically significant. As expected given the smaller sample size the confidence intervals for model 3 are wider than for models 1 and 2 and so we can be even less certain of the true magnitude (and direction) of the effect.

5.2.3.2.2 Event day late peak period results (18:00 – 20:00)

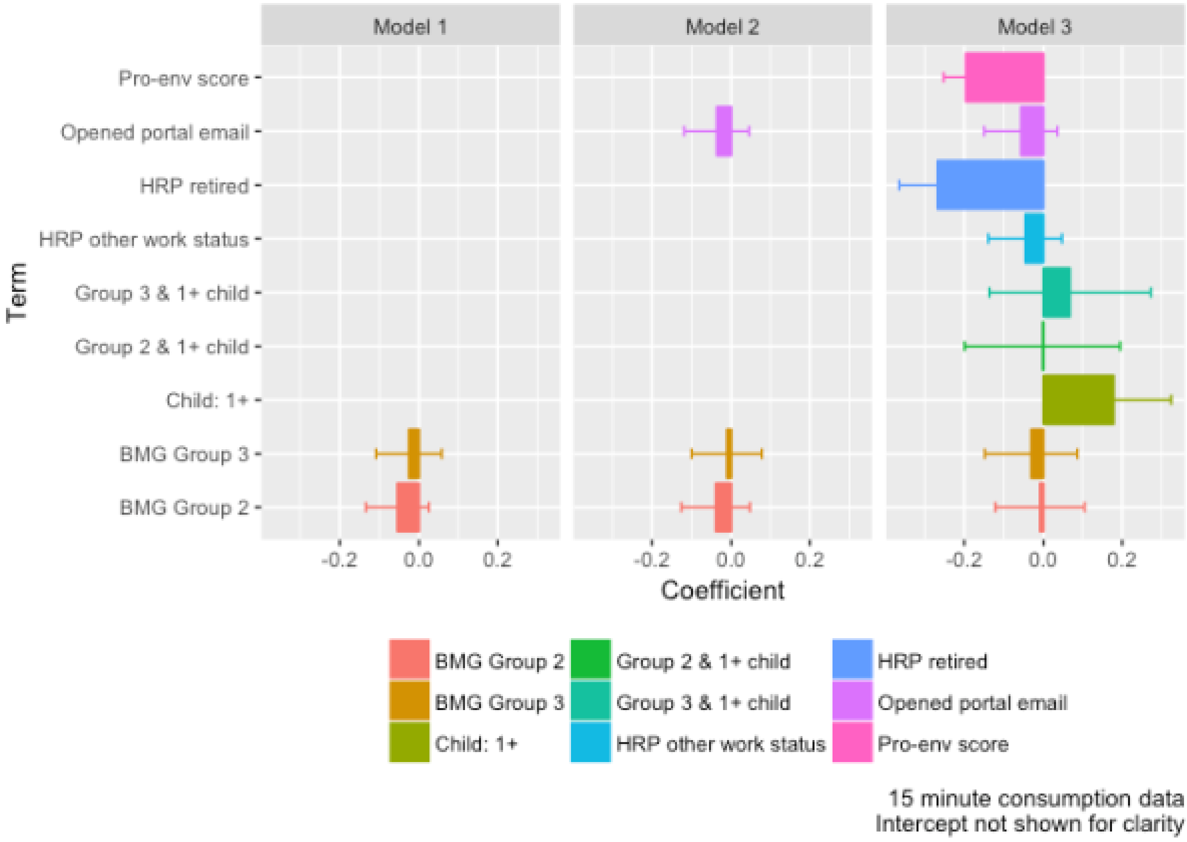
Based on the 24 hour profile chart above (Figure 19), it seems that the largest difference was found in the period 18:00 – 20:00. The following analysis (Table 6 and Figure 24) therefore repeats the initial regression analysis but only for this specific period.

Table 6: Event day peak period regression model results (18:00 – 20:00)

	Dependent variable:		
	Log(Mean Wh)		
	Model 1	Model 2	Model 3
	(1)	(2)	(3)
Group 2	-0.055 (-0.134, 0.025)	-0.039 (-0.126, 0.049)	-0.008 (-0.122, 0.105)
Group 3	-0.025 (-0.108, 0.057)	-0.011 (-0.100, 0.078)	-0.031 (-0.148, 0.087)
Email: Not applicable			
Email: Opened		-0.036 (-0.119, 0.046)	-0.057 (-0.150, 0.037)
1+ child			0.179* (0.033, 0.324)
HRP Retired			-0.267*** (-0.364, -0.171)
HRP: Other work status			-0.046 (-0.139, 0.048)
Pro-environment score			-0.196*** (-0.252, -0.140)
Group 2 & 1+ child			-0.002 (-0.199, 0.195)
Group 3 & 1+ child			0.068 (-0.137, 0.272)
Constant	4.847*** (4.790, 4.904)	4.847*** (4.790, 4.904)	5.453*** (5.269, 5.637)
Observations	2,850	2,850	1,997
R^2	0.001	0.001	0.070
Adjusted R^2	-0.0001	-0.0002	0.066
Residual Std. Error	0.903 (df = 2847)	0.903 (df = 2846)	0.849 (df = 1987)
F Statistic	0.906 (df = 2; 2847)	0.851 (df = 3; 2846)	16.624*** (df = 9; 1987)
Note:			*p<0.05;* ***p<0.01;*** p<0.001

Overall the results are broadly similar but the magnitude of effects is larger, especially for Group 2. However neither of the trial group effects is statistically significant.

Figure 24: Event day peak period regression results (18:00 – 20:00)



5.2.3.3 Summary

Overall the results for the mean Wh analysis suggest that the interventions produced a small decrease in consumption during the event day peak period. They also produced a small increase during the evening peak period of the day before and also the periods just before and just after the event day peak time. However, none of these effects were found to be statistically significant at the standard 95% level and this was true for all models and trial interventions. This resonates with previous work that has demonstrated the relative ineffectiveness of financial incentives in reducing peak electricity consumption (Delmas, Fischlein, and Asensio 2013; AECOM 2011; Bradley, Coke, and Leach 2016). This will be further investigated in future trial periods providing a greater understanding into how attitudes may change with different incentives and over multiple rounds of engagement.

There was also no statistically significant interaction effect between the presence of children and membership of a particular trial group although the size of the observed effects did vary for those with/without children suggesting potentially differing patterns of response by different kinds of households.

However, the analysis team has also identified that overall those who have children and households whose response person was retired have significantly different consumption patterns in the time periods analysed. Those with children tend to use more in the 16:00 onwards period whilst those with a retired household response person use less. The opposite is the case for the pre 16:00 period. Overall those with higher pro-environmental scores as reported in the household surveys use less electricity in any period.

Finally, the adjusted r^2 score[22] reported in each regression results table indicates the proportion of variance in log(Mean Wh) that is explained by the model. None of the models achieve greater than 7% which indicates that the variables included are very poor at modelling log(Mean Wh) even when some seemingly important households characteristics are included. This is not a problem and r^2 scores should improve if intervention effects become larger and statistically significant. However, it does also draw attention to the inherent variability in electricity consumption from one household to the next.

5.3 Trial Period 2 Planning

Trial period 2 (TP2) will build on the results of TP1 and continue participants' educational journey through additional and/or expanded objectives. The design of TP2 also reflects the learnings gained through the literature review at the beginning of this project and summarised in SDRC 1.

5.3.1 LED Trial

While TP1 tested participants' likelihood to 'opt-in' by purchasing discounted light bulbs, TP2 will focus on the direct installation of LEDs in households that did not take advantage of the offer in TP1. This will test participants' willingness to accept the offer and be phrased such that they need to 'opt-out' if they do not want the team to install the bulbs. This offer will only be solely for group 2.

5.3.2 Consumer Engagement

The consumer engagement campaign will continue in trial period 2, although it will only be directed at groups 3 and 4. It will build on the general information distributed in TP1 but with a focus of cutting energy use during the peak period (rather than shifting it outside the peak). This trial will also incorporate more advanced engagement through the use of comparisons, personalised targets and more creative media.

[22] The R-squared score (or coefficient of determination) is a standard measure of the performance of a regression model. It indicates how close the data are to the fitted regression line. Since increasing the number of variables in a model automatically increases the r-squared score, analysts use the adjusted r squared score to control for this.

Since DNOs currently only have access to mailing addresses and cannot access more personal contact information (such as emails or mobile numbers), the project has structured TP2 to test two realities. The first half of TP2 (October, November and December 2017) will involve only postal engagement. While TP1 mainly sent out booklets and postcards that are likely to get thrown away after reading (or sometimes before); TP2 will include more tangible items that are likely to stay in the home for longer periods of time. The postal mailings will start with an initial 'welcome pack' that includes a small booklet with general information on reducing electricity usage and the peak periods as well as a selection of stickers, note books, and calendars. The hope is that these items are used within the house and serve as a more frequent reminder to cut energy consumption without being obtrusive. The welcome pack will be followed up with a handful of postcards throughout the first half of TP2 with tips on cutting energy consumption. While consumers can still log onto the Loop portal and view their energy use, it will not be used to send messages to consumers. Email messaging will not be used during this time. This will reflect the methods of engagement currently available to DNOs.

The second half of TP2 will be digitally focussed and will not include any postal mailings. This portion of the trial will encourage people to use the portal to view their energy use and all messaging will be sent via email and portal notifications. The 'cut' message will remain constant throughout.

Like TP1, TP2 will also include event days for groups 3 and 4. These will be explained in a similar fashion as in TP1; noting, the network is experiencing a period of stress and asking that participants cut their usage during a specific time. Unlike TP1, there will be multiple event days on different days of the week, possibly for different durations and times of the day.[23]

The analysis of the event day in TP1 showed that the largest decrease was in the period from 18:00 to 20:00, future event periods will build on this learning and test if shorter event periods are more effective than long ones.

The event days will happen in both the post only engagement period as well as the digital engagement period. During the first half of TP2, participants will receive notifications via a letter in the post, to be delivered 2 to 3 days before the event. During the second half, participants will be notified by email 2 to 3 days before the event and by text the day of the event. The Loop portal will also have a notification that sits at the top of the newsfeed for the days leading up to the event. Feedback will be provided to the customers informing them if they successfully met the asked reduction or not.

[23] The team is considering the impact that changing the time of the event day to something different than 4 to 8 will have on participants and mitigating against any potential confusion. The team is reaching out to other DNOs that have executed event periods with load shifting on residential customers to see if their participants easily followed the ask or if they expressed confusion.

5.3.3 Price Signalling

Group 3 will be offered incentives to meet their targets outlined above. Since the project has already tested small incentives using the £10 voucher[24] in the previous trial period, TP2 will utilise different incentives. By altering the incentive levels across the trial windows (so long as staying within the £/kW upper payment limit defined by the Pricing Model and previous commercial analysis) the project will look at best understanding price elasticity of customers and hence the minimum payment level required to achieve desired levels of load-reduction. Some payment mechanisms within TP2 are also likely to be in the form of prizes but the team will determine exact specifications closer to the trial period. The goal of this kind of price signalling is to offer a bigger reward to fewer individuals, like a raffle or prize draw.

In TP1, reduction rates were similar across the price signalling group and the group without price signals. This is consistent with past literature that suggests 'one-off' requests to help the network resonate with consumers and do not need to be accompanied by financial incentives (Strengers 2012; Strengers and Maller 2012). TP2 will test if this result persists or if the non-financial group is fatigued by multiple asks. It is possible that over time the non-financial group may lose interest in helping the network while the financial incentives can keep households engaged for longer periods of time.

6 Recommendations and Learning Outcomes

This report has compiled the viewpoints and expertise of industry professionals alongside project learning obtained through live trials on SAVE. It is important to highlight from this report that for a DNO to successfully lead domestic DSR multiple different avenues of support and impact must be considered.

The pathway to domestic DSR to address network issues is far from straightforward with decisions and direction needed in relation to the customer interface (as illustrated by Economy 7 and the data informed engagement in SAVE), supporting technologies (whilst largely outside the scope of this project, functionality of the Navetas Loop will be explored within TP2), the level and type of payment (informed by SAVE pricing model and CPP/ ToU illustrations) in addition to the commercial mechanisms focused on within this report.

Focusing on the commercial mechanisms through which a DNO could pass price signals to customers this report identifies four avenues that fall within DCUSA (c, e, f, g) and three that fall outside of it (a, b, d).

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DCUSA is a multilateral contract and all licensed suppliers and DNOs are party to it. Any change to DCUSA automatically applies to all suppliers and there is no need to enter into separate agreements with individual suppliers. However, this relative convenience does not necessarily provide added simplicity and comes at the cost of flexibility. Agreements outside DCUSA can be tailored to individual circumstances and can be amended without going through industry governance processes and Ofgem approval. Ultimately industry must work together to identify the solution which considers whole system impacts and costs (to DNO's, suppliers and other third parties) to provide best value to consumers.

If implemented, option (a) direct payment to customers, would require the creation of new billing and banking arrangements to process direct payments. Meanwhile options (b), indirect payments to customers through their supplier, and (c), indirect payments to customers through their supplier under DCUSA, on the other hand will pass the obligation of incentive payment to customers onto suppliers. This favours the chances of a customer receiving payment under this option as opposed to others (d, e, f) which rely on competition between suppliers.

Both options (f), payments to suppliers through credits against their DUoS bills, and (g), payments to suppliers through special DUoS tariffs, would require changes to the DUoS charging arrangements within DCUSA. Under option (g) the payments are automatically calculated as part of DUoS charges based on the approved DUoS methodology, whereas under option (f) the payment would have to be calculated separately and applied as an aggregate discount or credit in each supplier's DUoS bill.

Under the DUoS options, the payment is likely to be treated as negative revenue because it would be applied against DUoS charges. For options outside the DUoS charging arrangements, the payments could be treated as costs or negative revenue, and further work including engagement with Ofgem will be required to identify the most appropriate treatment.

Payments under option (g) are constrained by the structure of DUoS charges to eligible customers. For instance, it would not be possible to make a payment based on consumption at different times of the day to customers who are on a single rate tariff. Under other options the payments are determined outside the DUoS charging methodology, so these can be structured independently of the DUoS charge and offers the scope for innovative approaches to these payments.

Another key consideration is geographical variation, for those options outside of DUoS there are possibilities to target specific payments based upon location. Within DUoS, under option (g) there would be the capability to target payments geographically, however it would not be possible to target specific payment amounts through a time of use tariff, as the payment depends on the consumption of the customer. It is for this reason that understanding of customer's receptiveness to price signals is key to determining anticipated network impact and anticipated level of payment. The possibility of targeting payments to domestic customers based on geographic location is clearly a significant departure from current arrangements and the social equitability of such an approach would be an important matter for further consideration.

Moving forwards the SAVE project will look to further industry understanding into domestic DSR, working closely within the commercial parameters outlined in this report alongside understanding both the cost parameters a DNO may look to work within (through the network pricing model) and the impact on the network that such varied price levels may have (through the project's trials). Given the notable implications on suppliers in both supporting domestic DSR and on their procurement of electricity, SAVE will look to continue and strengthen this engagement throughout the project's life-span. It is stated that each of these elements are of key consideration in considering "*a regulatory model and incentive model for DNOs to use in RIIO"* (SAVE Project Bid)

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8 Appendix

8.1 Appendix A - DNO price signals direct to customers trial report

8.2 Appendix B – Example of Pricing Model

8.3 Appendix C- Letter to Suppliers

8.4 Appendix D- Sunday Peak Analysis

8.5 Appendix E- Pre and Post Event Analysis

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