Analysis of Network Benefits from
Smart Meter Message Flows
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1. Background
The purpose of this paper is to provide a very high-level summary to describe, in non-technical terms, the compelling case for procurement of smart meter message flows to improve the efficiency of Britain’s electricity distribution networks. Such message flows would facilitate the development of smart grids, especially as GB transitions to a low carbon economy. The case is substantially made with the Energy Networks Association (ENA) Use Cases, Cost Benefit Analyses and the ENA commissioned ‘Benefits of Advanced Smart Metering for Demand Response Based Control of Distribution Networks Summary Report’ (ENA/SEDG/Imperial College) - referred to hereafter in this paper as the Imperial College report.¹

This paper does not cover every aspect of network management-related smart meter functionality described in the Industry’s Draft Technical Specification (IDTS); instead it addresses, collectively, the key functionality required for network management and smart grids in areas where further information is requested by DECC regarding clarification and/or quantification of benefits. The paper provides detailed answers to the specific questions posed by DECC’s ‘Analysis of network benefits from smart meter message flows: Data Request Table’ issued on 7 March 2012. A summary of the monetised benefits is included at the end of the paper together with discounted cash flow tables.

2. Network Visibility
The ENA has engaged fully with the Smart Metering Implementation Programme (SMIP) in order to ensure that the opportunity is taken to leverage the benefits arising from the GB smart meter programme, in terms of providing Network Operators with the means to monitor and where necessary influence control over demand and/or network running conditions. The context of this is that while Network Operators have well established monitoring systems covering their higher voltage systems, they currently have virtually no visibility of voltage levels and power flows on LV networks, and only limited visibility on HV (generally 11kV) networks.

¹Benefits of Advanced Smart Metering for Demand Response Based Control of Distribution Networks Summary Report (ENA/SEDG/Imperial College):
http://www.energynetworks.org/electricity/futures/smart-meters.html
Network Loading and Voltage - Because the loadings and load profiles of conventional domestic and SME electrical appliances are reasonably well known, the lack of monitoring functionality on LV networks has not been an issue to date. Diversity of demand is also well understood allowing LV networks to be designed to cater for the ‘after diversity maximum demand’ (ADMD) which is much less than the aggregate maximum demand that could theoretically be presented without diversity. For example, a modern gas heated 3 bedroom home situated on a housing estate would contribute around 1kW of demand as seen by the substation serving the estate, even though at any given time the demand presented by that single property might be several kilowatts. This means that a substation serving an estate of 100 such properties would experience a maximum demand of around 100kW.

Going forward, not only will electricity networks have to distribute the additional electricity energy required to serve new low carbon technologies (LCTs) such as electric vehicles (EVs) and heat pumps, they will also need to have sufficient capacity to accommodate the higher system maximum demand that will be presented. However, because the consumer usage patterns of these technologies (especially EVs) is not yet understood, and may in any case vary considerably between consumers, it will be important for Network Operators to have visibility of how demand is building on their networks, especially as a large proportion of those networks will have been designed to cater only for the electrical energy distributed today.

A further consideration for Network Operators is the impact of micro-generation such as photovoltaic (PV) and microCHP. These generation technologies will introduce localised reverse power flows whenever generation output exceeds the demand at any given property, and this in turn will give rise to changes in the voltage profile, potentially causing voltage to rise above statutory limits.

It follows from all the above that Network Operators will need visibility of both half-hourly demand profiles in terms both of import and export, and also half-hourly voltage profiles at strategic positions along LV networks. It will also be important to monitor power factor since some LCTs (such as heat pump motors and compact fluorescent lamps) will have lagging power factors and will create unwanted reactive flows in LV networks. Uncorrected reactive flows will further increase loadings on LV networks while delivering no additional useful power, and will also create further variations in voltage.

Network Operators will therefore need to have visibility of ‘4 quadrant’ demand (or energy) profiles (import, export / real and reactive). Network Operators will use these profiles to ascertain loadings on individual sections of LV networks in order to check that the aggregate demand does not exceed the thermal ratings of lines and cables. Similarly, voltage readings will be taken at various positions along individual sections of LV networks in order to check that the voltage remains within the statutory limits (230V ±10%/-6%). Aggregate demand values will be generated by summating individual synchronised demand profiles from smart meters, which should alleviate concerns over data privacy.

The ENA has identified benefits that would accrue to Network Operators (and hence to consumers) from increased network visibility, even today before the impact of LCTs becomes significant. This benefit would arise from refined planning and network investment decisions - in terms of scale, targeting and timing of investment - purely as a result of the improved network loading, power factor and voltage data available.

Power Outages - A further major customer service benefit opportunity from smart metering is that of much improved management of power outages due to faults on LV networks and HV overhead line spurs. Network Operators collectively experience
upwards of 100,000 faults per annum on LV circuits, the identification of each of which is dependent on at least two affected consumers telephoning the Network Operator’s call centre to notify a loss of supply (a single consumer call might indicate a fault on the consumer’s internal wiring, the operation of the main fuse adjacent to the meter, or a fault on the service cable serving that property). Under storm conditions, a Network Operator might experience hundreds of LV faults over a period of a few hours (compared with an average of around, say, 20 per day for each of the 14 licensed networks). These faults will be largely invisible to the Network Operator, since consumers are likely to have experienced difficulties in making contact with call centre staff (due to the sheer volume of call traffic) and/or because at the time of the call it will generally be impossible for call centre staff to differentiate causes of supply failure between those due to HV and LV faults (i.e. because the areas affected by the HV faults will initially be very wide and hence a large proportion of the LV faults will fall within the ‘catchment’ area of the HV faults).

Efficient power outage management will become increasingly important as greater reliance is placed on electricity for residential heating (e.g. heat pumps) and private transport (i.e. EVs). Moreover, it is clear that the inconvenience cost of loss of supply will increase. Hence a more rapid and efficient response to LV faults is a prerequisite to maintaining customer satisfaction with service levels. It follows that current assumptions over willingness to pay (based on current valuations of inconvenience due to loss of supply) are almost certainly understated when considered against the ‘inconvenience’ scenarios applicable to a future with electrified home heat and personal transport (for example waking up at 0630 to find an EV with a flat battery due to an undetected power failure in the early hours of the morning).

Whilst ENA has identified cost benefits in terms of improved field resource utilisation when LV faults occur (especially under storm conditions) the major benefit is that of greatly improved customer service during power outages. Albeit that the impact on a DNO’s overall ‘customer minutes lost per customer’ quality of supply performance will be small, this is a tangible benefit for consumers and one which should enhance consumer acceptance of the smart meter programme.

3. How smart meter data would be used

Network Visibility - Given the numbers of EVs, heat pumps and domestic PV generation installations predicted under DECC’s 4th Carbon Budget scenarios, the need for visibility of voltage levels and power flows on LV networks will become acute. To provide such visibility other than through smart metering functionality would be costly and largely impractical, and would give rise to arranged electricity network shutdowns in many cases in order for the monitoring equipment to be installed. Smart metering, on the other hand, is able to provide such functionality at a more granular level (and such granularity will in any case almost certainly be necessary in future due to clustering of new LCTs) and at a minimal incremental cost. Visibility will be provided as follows:

i. The meter will provide half-hourly power flow data across 4 quadrants (that is to say: imported real power, exported real power, imported reactive power, and exported reactive power) (T6.2.2).

Some network operators have previously installed power outage devices (PODs) in a very limited number of homes in order to provide indications of problems on rural HV networks where no SCADA communications are available. However, their coverage would be nowhere near sufficient to provide a comprehensive LV fault monitoring capability.
ii. Supplementing this will be the ability to check the maximum demand (note: this does not give energy consumption data) recorded by any given meter so that where new connections of LCTs or other loads have been connected, or are being proposed, it will be possible for the Network Operator to check that the loading is within the rating of the service cable and termination, and that it will not lead to thermal overloads or voltage issues over the wider LV network.

iii. Checking maximum demands at a given time (for example during the winter evening peak demand period) at meters connected to a given section of LV network would also enable the Network Operator to check the aggregated maximum demand at that time on that section of network. The 12 hour latency would enable the results to be presented during the following working day which could be particularly beneficial if the routine 4-quadrant half-hourly profiles for the current winter quarter (TS6.2.2) had not been downloaded at that time. This is the functionality underpinning T6.3.26.

iv. The Network Operator, having previously mapped each smart meter to the local LV network serving that property, will aggregate this half-hourly time series data in order to derive the total loading on that LV network and the half hour by half hour demand profile for that network across the day. Aggregated to the HV/LV substation level this will also enable Network Operators to determine how demand is distributed along HV feeders serving distributed substations (SCADA information is limited to power flows leaving the source EHV/HV substation).

v. This load profile would be compared with the thermal rating of the LV network to ensure that at no time (i.e. at times of peak load) does the loading exceed the capacity of the network.

vi. The derived load profile would enable the Network Operator to determine the thermal capacity headroom of that LV network to accommodate additional loads such as EVs and heat pumps. It would also enable improved turnaround times in respect of requests for new connections to the network and greatly inform Network Operators’ priorities for load related reinforcement as more EVs and heat pumps connect to the network.

vii. Visibility of these derived profiles would also help avoid unnecessary reinforcement that might otherwise have been undertaken due to overestimated demand. Conversely, the derived load profile would also help avoid problems due to existing demand being underestimated and new connections to the network then creating subsequent overloading.

viii. The ability to aggregate export data would also identify reverse power flows which might require specific measures to be taken (see also voltage profiles below).

ix. Similarly, the ability to aggregate reactive power would enable Network Operators to identify where power factor correction might be necessary and/or enable an efficient alternative to capacity related network reinforcement.

x. The aggregated nature of the above data (to the LV network level) should allay any concerns over data privacy.

xi. As well as power flows, it will be essential to also monitor voltage levels. Modelling has shown that increased connections of EVs and heat pumps will give rise to lower voltages along LV circuits (due to ‘voltage drop’ caused by higher network loadings).
xii. Meanwhile, micro-generation (especially PVs) will cause voltage to rise on parts of LV networks during light load conditions. DECC’s 4th Carbon Budget medium and high PV scenarios at 2030 are 1.8m and 3.6m installations respectively. In terms of installed capacity, 3.6m installations equates to 16GW which, at an assumed load factor of 9.7%, gives rise to 14TWh of generation. 16GW represents approximately half of national summer afternoon minimum demand (see chart below). It follows that under summer minimum demand conditions significant net export of PV generation from LV networks will occur, giving rise to the need for active management of LV network voltage levels.

xiii. Network Operators are required (by law) to maintain voltage within the statutory limits of 230V +10% -6% (i.e. between approx. 216V and 253V) at the point of supply. It is anticipated that the combined effect of EVs, heat pumps and micro-generation will be to cause much greater voltage swings. Hence it will be essential to ascertain whether the voltage on any part of the LV network or at any consumer’s supply terminals is approaching and/or in danger of exceeding statutory limits.

xiv. It follows that, in addition to power flow data, it will be equally important to capture half hourly voltage data (T6.2.2) so that the voltage profile along an LV circuit can be derived throughout the day. PVs are most likely to cause voltage rise problems during summer mid-morning and mid-afternoon periods whereas EVs and heat pumps are most likely to cause low voltage problems during the late afternoon / early evening period of winter weekdays.

xv. There is no practical means by which this monitoring of voltage could be effected to the required level of granularity other than through smart metering (the level of granularity is required because excursions beyond statutory limits could occur at any point along an LV network or at any consumer’s supply terminals).

![National weekday demand profiles](chart)

**Power Outage Management** - Consumers might reasonably expect that a ‘smart’ meter with two-way communications would be able to both detect a loss of supply and automatically inform the Network Operator; indeed this functionality might be
considered by consumers to be one of, if not the, most important benefit(s) of the smart metering system. This capability will be realised through the following functionality:

i. The meter will log a time-stamped event when the power fails (but first allowing sufficient time for any network automation scheme - typically 3 minutes - to take effect and restore supplies).

ii. The meter and communications hub will signal a loss of supply to the Network Operator, enabling the Network Operator to immediately identify the location and extent of the supply failure – and hence alert customer call and field resource dispatch centres (T6.3.9).

iii. On restoration of supply, the meter will log a time-stamped restoration event (T6.3.50). Taken together with the time-stamped outage event, the Network Operator will then be able to accurately determine the period of the outage and hence accurately report the duration of interruption and numbers of consumers affected, and also determine if a Guaranteed Standard has been breached.

iv. A final check on supply restoration will be possible by the Network Operator selectively polling meters (or communications hubs) to check their energisation status (T6.3.19). This functionality will be particularly useful in storm scenarios as described in 2 above, i.e. in being able to identify LV network faults previously masked by faults on the associated upstream HV network.

**Demand Side Management / Response** - The greatest benefit of smart meter functionality will be in minimising the impact on electricity bills due to low carbon transition; i.e. by:

- enabling Suppliers (or potentially new players such as ESCos, Commercial Aggregators or Virtual Power Plant Operators) to influence consumer demand such that it more closely follows the near real-time availability of low carbon variable generation (such as wind, photovoltaic and tidal); and/or
- enabling Network Operators to maximise the load factors and utilisation levels of their existing networks and hence create capacity headroom to accommodate LCTs while minimising the need for costly reinforcement and disruption to daily activity (for example due to street works and arranged electricity network shutdowns to undertake electricity network reinforcement works).

These two drivers will not always be mutually supportive and could (as this paper describes later) sometimes be in conflict. Nevertheless, irrespective of synergies and conflicts, there will always be an optimum load profile that reconciles both drivers to achieve the lowest overall delivered energy price for consumers by means of the functionality described below.

i. Through determining LV network power and voltage profiles, it will become evident as to where mitigating or corrective action is required. As EV, heat pump and PV volumes increase, so the need for interventions will increase.

ii. One means of deferring or avoiding network reinforcement (given that the Network Operator will have visibility of the daily load profile for a given LV network) would be to encourage demand shifting away from the peak demand period and towards periods where demand is relatively light.

iii. One approach would be to introduce time-of-use tariffs. However, the 'price signal' available through purely a use-of-system tariff would be too small to be
very effective. Hence it will generally be necessary for Suppliers to supplement the use-of-system price signal by also introducing an energy time-of-use tariff reflecting the higher marginal cost of generation at peak demand times (the Network Operator will in any case be dependent on the Supplier reflecting the use-of-system charge within the energy time-of-use tariff).

iv. Given a combined energy and network price signal, it might be expected that some voluntary movement of demand away from peak periods will be possible. However, it is likely that any significant movement will be dependent on the wide adoption, over time, of ‘smart’ appliances.

v. It is likely, however, that some direct control of demand, especially EVs, will become necessary if excessive peak demands are to be avoided (unconstrained, EV home charging and heat pump usage might reasonably be expected to peak at around 1800 - which coincides with the time of winter weekday peak demand).

vi. Hence it will be important to ensure that at least a basic level of load control functionality (i.e. through auxiliary switches) is incorporated within the smart meter. Consumers will be incentivised to release control through the benefits of lower tariff prices (avoiding high price periods of time-of-use tariffs). This is the functionality described by T6.2.4, T6.2.5, T6.2.6, T6.2.7, T6.2.8 each of which refers to an auxiliary switch function to control individual LCTs or other forms of flexible demand (such as electric water heating). It is therefore anticipated that Suppliers would require this functionality.

vii. Initially, in most cases, local network peak demand will coincide with system (and hence generation) peak demand. Hence there should be synergies to both Suppliers and Network Operators in introducing time-of-use tariffs encouraging consumers to shift demand away from peak periods.

viii. However, as greater volumes of wind generation are introduced to the national generation portfolio, Suppliers will increasingly look to design time-of-use or dynamic tariffs which will encourage consumers to control their electricity usage so as to ‘follow’ as far as practicable wind generation output.

ix. Initially, ‘wind following’ tariffs might be introduced on a ‘day ahead’ pricing basis so that consumers can plan their electricity usage in advance - for example washing and drying clothes on days when wind volumes are expected to be high and hence electricity prices relatively low.

x. The Tempo tariff introduced by EdF in France 1993 is based on day-ahead notified critical peak pricing. Day-ahead prices are determined from forecast weather conditions. The tariff has demonstrated that provided pricing signals are both clear and sufficiently strong, domestic consumers are able to provide significant levels of responsive demand even without LCTs or smart appliances (see inset box overleaf).

xi. Unlike conventional fossil-fuelled or nuclear generation (which is demand following) wind generation peaks will not necessarily coincide with natural demand peaks, and so the natural synergy between network and generation marginal costs will drift as wind generation availability increases. Network Operators will then become increasingly exposed to energy time-of-use tariffs which, instead of helping to shift demand away from network peak periods, might actually increase demand at times of network peak if wind volumes are high at that moment in time. The chart below indicates how a wind following tariff might impact EV charging behaviour and create a higher than normal national evening peak demand.
It follows that with higher volumes of wind generation, Supplier led time-of-use tariffs will not necessarily shift peak demand in a way that is complementary to relieving network constraints and releasing network capacity headroom to accommodate EVs and heat pumps (see Imperial College Report section 5.14 – 5.15).

Impact of wind generation output on peak system demand

Source ENA/SEDG

### EdF Tempo Tariff

- The Tempo Tariff critical peak pricing program, was implemented in 1993 and uses a colour-coded approach (blue / white / red) to notifying consumers of prices on a day-ahead basis.
- The red days are restricted to the period from 1 November 31 March and occur between Monday and Friday, never at a weekend or on public holidays. The system is designed to encourage people to think about when they use dishwashers, washing machines, tumble dryers and other flexible electrical appliances.
- The colour of each day is determined by EdF and based on the forecast of electricity demand for the following day which is mainly influenced by the weather. RTE, the French transmission network operator, also has the ability to determine the day colour if there is significant congestion on the electricity network.
- Customers who choose Option Tempo are informed each night about the colour for the next day. At 8 pm a signal is sent down power lines using a ripple control system. Most Tempo customers have a display unit that plugs into any power socket and picks up the signal. The display unit shows the day colour with lights, both for the current day and (from 8pm) for the next day. An (optional) beep informs the consumer if the following day will be a red day. The display unit also shows whether or not the current electricity price is at the off-peak rate.
- Prices for electricity purchased under Option Tempo (as published in June 2005)
  - Blue days off-peak: 2.99 euro cents
  - Blue days normal: 3.81 euro cents
  - White days off-peak: 6.51 euro cents
  - White days normal: 7.79 euro cents
  - Red days off-peak: 12.42 euro cents
  - Red days normal: 35.46 euro cents
- **Customer Savings** - Tempo customers have saved 10% on average on their electricity bill.
- **Customer Satisfaction** – There are 400,000 customers on the Tempo Tariff. EDF has found a 90% satisfaction level. However, customers do not appreciate red days occurring consecutively.
- **Impact on Peak Demand** - Peak demand reduction is 450MW compared with blue days. The Tempo tariff has led to a reduction in electricity consumption of 15% on white days and 45% on red days - on average 1 kW per customer. EdF studies have shown that 7 million customers could significantly benefit from the Tempo tariff which could lower demand by 6GW on red and white days; consumption would actually increase by 2GW during the blue days.
Power Quality Monitoring - It is widely anticipated that increased penetrations of LCTs will give rise to new or increased levels of power quality issues, such as voltage dips (e.g. due to heat pump starting currents); local voltage swells (e.g. due to the potential for PV generation output to ramp up suddenly when the sun emerges from a cloud); and increased levels of harmonic distortion (due to inverters associated with PVs and potentially EV charging stations if 'vehicle-to-grid' activity becomes prevalent). Whilst a smart meter has limited capability to provide power quality data, it can nevertheless provide early warnings of where power quality issues are emerging.

i. Voltage sag and swell detection, at least at a non-sophisticated level, is easily accommodated within the functionality of the smart meter, as is the ability to record high / low (and extreme high / low) voltage events. Whilst it is difficult to quantify the benefit at this stage, there is every reason to believe that this functionality will prove increasingly valuable as volumes of EVs, heat pumps and PVs increase, i.e. in giving early warnings of emerging power quality problems, enabling Network Operators to make timely interventions before the problem becomes sufficiently acute so as to cause consumer inconvenience and potential damage to electrical appliances. This is the requirement underpinning T6.3.51 (sag/swell)

ii. A further complementary function is the ability to set voltage alarm thresholds as voltage is approaching the higher or lower statutory limits due to the impact of LCTs. This is the requirement underpinning T6.3.4 (high/low voltage). Network Operators might use this facility to prioritise locations from which to take half hourly voltage data under TS6.2.2.

iii. Under certain rare conditions the voltage received by consumers can rise above / fall below statutory limits to an excessive degree. This condition arises primarily through failures of the LV neutral conductor; one specific cause being copper theft from substations. Detection of extreme voltage events is effected through similar functionality to the high/low voltage alarm under T6.3.4 above, but with higher and lower threshold settings, and requiring much faster latency associated with the alarm signal (ideally the smart meter would self-disconnect under these conditions). Note: these two variations on T6.3.4 are identified separately in the IDTS.

Active Network Management - Notwithstanding the potential benefits of responsive demand (and/or load switching) in terms of peak shifting, it is clear from the above that generation-led peak shifting will not necessarily create the ideal load curve from a network constraint management perspective. Network Operators will therefore need to take further steps to maximise the available capacity of their networks through more Active Network Management.

Active Network Management will take a number of forms, but the objective will be to create further capacity headroom so that yet more LCTs are able to connect to the network without causing thermal overloads or statutory voltage transgressions. Examples of Active Network Management will typically include:

i. Active voltage control of LV networks (to compensate for the wider voltage swings referred to above); key to this functionality will be low latency voltage information from a number of pre-selected strategically placed smart meters. For the reasons stated above, it is widely predicted that active management of voltage at the LV network level will become necessary due to LCTs and especially PVs. Only by accessing voltage information from smart meters will
it be feasible to accurately determine voltages experienced by consumers. This is the requirement underpinning T6.2.1.

ii. Active management of power factor (which will reduce both unwanted reactive power flows and voltage swings - and so release both thermal capacity and voltage headroom) which will be informed by 4-quadrant power flows under T.6.2.1.

iii. Switching of LV (and possibly HV) network open-points in order to shift load dynamically between sections of the network according to their relative loadings and headroom capacities. Such switching could occur on an intra-day basis although a more practical application, at least initially, might be intra-week (weekday / weekend) or seasonal (summer / winter) switching where the load balance between adjacent circuits varies over these periods. Again these actions would be informed by 4-quadrant power flows under T.6.2.1.

iv. More sophisticated co-ordination of demand side actions (such as EV charging and generation dispatch) in conjunction with supply side (distribution network) actions. Confirmation of effectiveness of such actions is facilitated by selective monitoring; this is the requirement underpinning T6.3.1.

v. An important complementary function to monitoring the impact of active management of demand is that of the meter to signal in the event that a consumer has exceeded a maximum demand or energy usage threshold in any given half hour, and subsequently to provide confirmation that the intervention to correct the condition has been effective. This is the functionality underpinning T6.3.54, T6.3.55 and T6.3.56 respectively. Again, the expectation would be that Suppliers will also require this functionality for load management purposes.

vi. As a backstop measure to deal with demand potentially in excess of the service cable and termination rating and/or groups of demand giving rise to excessive utilisation of LV network capacity, a load limiting function could be implemented such that above a certain configured maximum demand threshold, the integral meter isolating switch would open automatically. This is the functionality underpinning T6.2.3.

4. Summary
The purpose of the above has been to provide an essentially non-technical description of:

- the purpose of various aspects of smart meter functionality specified by the ENA for network management purposes;
- the context of that functionality in terms of how it will become increasingly essential as we transition to a low carbon economy; and
- the consequential levels of penetration of EVs heat pumps and micro-generation which can be anticipated to impact LV distribution networks.

There is considerable uncertainty regarding:

- the speed at which LCTs will be taken up (as is evident in comparing DECC’s 4th Carbon Budget scenarios);
- the totality of the impact these LCTs will have on electricity distribution networks;
and the extent to which clustering might give rise to disproportionate impacts on specific LV networks.

It will therefore be important to take every opportunity to maximise flexibility and optionality in terms of the range of smart interventions that can be applied in order to avoid costly and disruptive network reinforcement (the PV of which is estimated by the Imperial College report at between £0.5b and £10b depending on rate of take up of EVs).

The requested smart meter functionality provides for the necessary range of monitoring and interventions that are likely to be required as part of an holistic approach to network management and smart grid development; a classic case of the whole being greater than the sum of the parts (no one function can be discarded without undermining overall flexibility and optionality).

It is impossible to predict at this stage the relative extent to which time-of-use tariffs (alone); responsive demand; and Active Network Management might individually provide the degree of intervention required in the early stages of low carbon transition, but it is almost certain that all three will play a major role as LCTs volumes increase. The diagram below from the Imperial College report shows the potential impact on system maximum demand of unconstrained EV charging and use of heat pumps compared with the relatively small impact if the 'ideal' load shape (100% load factor) could be achieved. In practice, it is extremely unlikely that the ideal daily load shaped will be achievable, even with time-of-use tariffs, responsive demand, and Active Network Management all working in tandem. The objective therefore will be to achieve a load profile as close to the optimised profile as practicable.

![Non-optimised heating / charging cycle](image1)

![Optimised heating / charging cycle](image2)

Source ENA/SEDG

The smart meter functionality specified by ENA is known through liaison with meter manufacturers to have minimal impact on the cost of a smart meter. Apart from ‘Last Gasp’ functionality (the cost of which will be significantly dependent on the WAN communications system provided), cost estimates for the full range of functionality requested are in the order of £1 per meter (or 6p per annum assuming a 15 year life).

Moreover, ENA has critically assessed the required WAN impact of accessing this functionality in terms of data volumes, frequencies and latency. ENA does not believe that any of the functionality will give rise to a need for significant (if any) additional WAN capability above that required to support the transmission of routine meter consumption, configuration and messaging data required by Suppliers.
The ultimate cost of not providing this functionality is likely to be substantial in term of incurred (avoidable) network reinforcement and degraded levels of customer service, and ultimately in terms of consumer disenchantment with smart meters and the Carbon Plan.

Most importantly, the smart meter functionality proposed by ENA will provide for flexibility and optionality in the future management of electricity distribution networks. The quantified impact of future high penetrations of LCTs is unknown but modelling suggests that in the absence of any alternative available strategy, significant investment in conventional network capacity will be necessary.

In terms of cost-benefit analyses or Impact Assessments, the preservation of flexibility and optionality in terms of future network management strategies should command a very high value, given the potential scale of the counterfactual costs of investment in network capacity that might become necessary if smart grid options are closed-out due to lack of smart meter data or functionality.
5. Remaining Questions
(Analysis of network benefits from smart meter message flows: Data Request Table)

Proactive Planning – better informed investment plans

Q1 - Is it still appropriate to use the DCPR5 allowance as baseline investment for the appraisal period (2012-2030)? How might the baseline investment increase over time in a business as usual case?

In terms of how the baseline investment might increase over time in a business as usual case, this will be critically dependent on the rate of conventional load growth (i.e. other than due to LCTs). Notwithstanding that there are likely to be significant regional variations, it is reasonable to assume that ‘conventional’ load growth due to increased population, employment growth and additional housing will show a significant upturn as Britain’s recovery from recession continues.

However, given that the rate of load growth might be mitigated by higher efficiency-rated electrical appliances and higher energy prices promoting energy efficiency generally, then it would be reasonable to assume that the baseline level of investment (i.e. net of any investment necessary to accommodate LCTs) would remain broadly similar to DPCR5 levels over the period 2012-2030.

With increasing numbers of EVs, heat pumps and micro-generation (especially PVs) then a ‘business as usual’ approach to network planning and operation would give rise to a need for significant network investment.

Taking DECC’s 4th Carbon Budget scenarios to 2030, and depending on the individual EV and heat pump growth scenarios chosen, EVs could present up to an additional 16.6TWh of demand while heat pumps could present up to an additional 49.5TWh. Scenario 3 would result in both of these additional demands being presented.

On that basis, national energy demand would increase to 416TWh, i.e. by 19% compared with today. Assuming load factor could be maintained at the current level then, in the absence of any other influencing factors it would be necessary to increase distribution network capacity by broadly the same amount.

The Imperial College report indicated that assuming 25% penetration of EVs and heat pumps by 2030 and assuming the penetration profile depicted in the chart below (both of which are broadly representative of DECC’s 4th Carbon Budget scenario 3) then the present value (PV) of conventional LV and HV reinforcement over the period from 2010 to 2030 could be in the range of £2.10b to 6.92b.

However, this takes no account of network investment required at higher distribution network voltages (e.g. 33kV and 132kV); nor does it consider the investment requirements for transmission (275 and 400kV) systems.

Taking the modern equivalent asset (replacement) value rMEAV of Britain’s electricity distribution networks to be approx. £100b, a national electricity energy demand increase of 416TWh would imply a need for some £19b in distribution network reinforcement over the period to 2030.
Q2 - Is there an expectation that investment savings are larger than 5% per year?

The DPCR5 allowance cited by ENA for the purpose of the CBA / IA was in respect of the DPCR5 ‘LV and HV General Reinforcement’ allowance. Higher voltage reinforcement was not considered on the basis that these (typically 33kV and 132kV) networks are already adequately monitored and hence investment decisions at these higher voltage levels would not be significantly better informed as a result of smart meter data.

As explained above it is the LV and HV (typically 11kV) distribution networks that have virtually no (LV) or limited (HV) power flow or voltage monitoring capability. Hence it is at these voltage levels that the smart meter data would provide the ability to refine investment decisions.

It is important to note that the estimated £4.4m p.a. (equivalent to a PV of £24.1m\(^3\)) saving was based on current business as usual (BaU); in other words the benefit that Network Operators would expect to derive today were the smart meter data available to them; i.e. before any significant increase in connections of LCTs.

Going forward, it is quite probable that the investment savings, purely through better smart meter data to inform investment decisions, would be higher than 5%. The reason is that, unlike conventional load growth which is gradual, largely linear, and predictable, load growth arising from LCTs will be much faster and much less predictable; it is also likely to cause degradation of power factor and create two way power flows. Hence only with the benefit of 4-quadrant power flow and voltage metering data could refined investment decisions be made.

The predicted scale and fundamental change in the nature of future load growth due to LCTs is unprecedented. Network Operators will be critically dependent upon information from smart meters in order first to understand the network impact that LCTs are having and then to enable them to make sound and timely decisions.

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\(^3\) PV based on assumed benefit from 2019 (full smart meter coverage) to 2025 (then superseded by responsive demand, demand side management and active network management benefits)
regarding interventions (through either conventional reinforcement of smart grid techniques).

Given the scale of the future challenge and the critical dependency on smart meter data, it is not unreasonable to assume that the conservative estimate of 5% of HV and LV network investment saving assumed for DPCR5 might rise towards 10% over the RIIO ED1 and ED2 periods, once significant volumes (or clusters) of LCTs appear. Based on the Imperial College report, and depending on the timing of the savings over the period, an average 10% saving in conventional (BaU) investment would deliver a present value (PV) benefit of between £81m and £268m assuming only 10% penetration of LCTs at 2030.

Based on DECC’s range of 4th Carbon Budget scenarios, 10% penetration of EVs and heat pumps by 2030 is pessimistic. Depending on which of the three DECC scenarios is considered, the Imperial College 25% penetration level at 2030 would be more representative of the level of conventional HV and LV network reinforcement required; in which case a 10% saving in conventional (BaU) investment would deliver a present value (PV) benefit of between £210m and £692m. On that basis, it would seem reasonable to assume a PV investment saving of at least £210m.

These present value investment savings are not to be confused with the anticipated savings predicted by the Imperial College report due, not only to refined (but still conventional) network investment decisions as a result of greater visibility of network voltage and loadings, but also to improved load factor as a result of time-of-use tariffs and responsive demand. At 10% penetration levels by 2030, the NPV of ‘smart’ (over the counterfactual conventional) investment ranges between £0.48b and £1.62b. At 25% penetration levels by 2030 by the NPV of ‘smart’ over conventional rises to between £1.36b and £4.47b.

However, it is unlikely in practice that load factor could be improved to the extent depicted in the Imperial College report through time of use tariffs and voluntary responsive demand (i.e. behavioural change) alone. It might therefore be prudent to assume a mere 15% of this saving is deliverable through this means, giving rise to a minimum anticipated PV investment saving of £204m4.

Q3 - What additional benefits can be expected by the following functions?

(T6.2.1 ES6-9 & ES10 Electricity Quality Read Programmed (half hourly data))
Please refer to Section 3 - ‘How Smart Meter Data would be used - Active Network Management’ above.

(T6.3.26 Maximum demand read measures peak)
Please refer to Section 3 - ‘How Smart Meter Data would be used - ‘Network Visibility’ above.

(T6.3.51 SMTS ES.10.9 Voltage sag/swell alarm)
Please refer to Section 3 - ‘How Smart Meter Data would be used - Power Quality Monitoring’ above.

These are complementary functions to other functions described in Section 3 above under ‘Active Network Management’, ‘Network Visibility’ and ‘Power Quality Monitoring’ above.

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4 The Tempo tariff is still in operation for consumers who have elected to be charged by this tariff but is understood to be no longer available to new customers.

5 It is important to note that this is based on the minimum NPV saving of ‘smart’ over conventional (BU) investment of £1.36b at 25% penetration levels; the maximum NPV saving being £4.47b at 25% penetration levels.
Monitoring respectively’. T6.2.1 contributes directly towards realising the benefits quantified in the Imperial College Report and summarised under Q2 above (i.e. optimising power flow and voltage to maximise network capacity headroom and hence defer the need for reinforcement) while T6.3.26 contributes directly to the to the ‘proactive planning’ quantified benefits quantified under Q1 and Q2 above.

T6.3.51 contributes directly to the Power Quality Monitoring functionality described in Section 3 above. Whilst it is possible to assign a potential DNO cost-saving benefit in terms of reduced power quality investigatory and complaint management costs, the overwhelming benefit is that of reduced inconvenience to consumers arising from early identification and resolution of power quality issues.

Depending on the size of their consumer base, a DNO might receive, each year, between a few and several hundred customer complaints or enquiries regarding supply voltage. Whilst the outcome in most cases is that the voltage is found to be within statutory limits, the majority of enquiries will nevertheless result in a need to install, and subsequently remove for analysis, voltage recording or power quality monitoring equipment. In terms of quantifying the cost saving, it is reasonable to assume that the need for temporary installations of voltage or power quality recording equipment would be significantly reduced, as would the administrative costs of processing customer complaints6.

Such savings would accrue even with current levels of electricity demand. However, going forward, LCTs are likely to give rise to much wider voltage swings on LV networks and hence it is reasonable to assume that voltage complaints or enquiries would tend to rise (albeit this trend would be offset due to the visibility of half hourly voltage profiles under T6.2.2.)

A conservative estimate based on current levels of voltage and power quality enquiries would be that DNOs as a whole might incur costs of around £500k per annum in site visits and administrative costs which could be avoided once full network coverage with smart meters is achieved. In the absence of voltage monitoring and alarm functionality these costs might conceivably rise to twice that level by 2030 due to the impact of LCTs. Overall the potential cost saving would equate to a PV of £5.9m across all DNOs.

Q4 - DECC’s analysis does not take into account new connections. What are the current and expected costs to developer seeking new connections, and by how much could these costs be reduced following proactive planning?

Costs incurred by Developers are in respect of sole-use assets the capacities of which are solely dependent on the required demand to be connected. Hence smart metering data would have little impact on these costs, other than in the sense of providing a more informed understanding of energy usage patterns and load shapes.

However, requirements for upstream works arising directly from new connections would be informed by smart meter data taken from existing connections to those upstream networks; such investment is subject to cost sharing principles. The DPCR5 Final Baseline Proposals for Demand Connections (i.e. the shared element of expenditure that is funded through use-of-system charges) was £345.7m across all Distribution Network Operators (DNOs). Assuming (reasonably) the same 5% saving under BaU as assumed for LV and HV general reinforcement, this would give rise to

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6 There might also be some savings in respect of GS5 payments but the failure rates and hence sums involved are trivial.
a further saving of £3.46m p.a. (equivalent to a PV of £18.9m\(^7\)) over and above the £4.4m p.a. saving (equivalent to PV of £24.1m) assumed for HV and LV general reinforcement.

**Active Network Management**

**Q1 - We understand that the Imperial College report results refer to demand side management benefits. How do the active network management benefits relate to the benefits identified in this report?**

The Imperial College report identified both the additional electrical energy consumption and the changing daily load profile (and hence the new peak demand) that would result from unconstrained use of EVs and heat pumps. The study then also demonstrated how the same level of electrical energy consumption could be accommodated but with a much smaller increase in peak demand if the 'ideal' daily load shape could be achieved.

However, achieving such a load shape through time-of-use tariffs implies real-time pricing, perfect price elasticity, and 100% flexibility of demand (i.e. that consumers have complete discretion regarding the times of day that LCTs and other flexible electrical appliances are used).

In practice, and since real time dynamic pricing is unlikely to be introduced for residential and SME consumers in the foreseeable future, this will not be feasible. As such, while some degree of peak shifting should be expected, the levels of load factor depicted by the study will not be realised, even assuming widespread adoption of smart appliances.

It follows that, in the absence of any other mechanism, the potential savings in LV and HV network reinforcement referred to in the study might not be possible. In order therefore to achieve further reductions in network reinforcement, and generate the necessary headroom capacity to accommodate EVs heat pumps and micro-generation, it will become increasingly necessary to introduce some measure of direct load control - perhaps through Suppliers, or in future Commercial Aggregators or Virtual Power Plant Operators (VPPs), and/or Network Operators undertaking Active Network Management.

While direct load control is fundamentally a demand side measure, Active Network Management is essentially a supply side measure and will include techniques such as load balancing, power factor control and active voltage control. These techniques will nevertheless rely heavily on information from smart meters to determine the action to be taken and to provide confirmation that the action has been successful.

Active voltage control of LV networks will almost certainly become essential under DECC’s high or medium scenarios for PV installations due the voltage rise effect when power flows on LV systems are reversed and the statutory requirement to maintain voltage within the prescribed limits of 230V+10% -6% at consumers’ supply terminals. Voltage measurements from smart meters will be essential to both monitor voltage levels and to provide inputs to local LV network voltage control schemes. This establishes the requirement for the functionality enabled by T6.2.1 and T6.3.4

Please refer to Section 3 - ‘How Smart Meter Data would be used - Active Network Management’ above.

The Imperial College report quantified benefits are essentially based on the value of releasing network capacity by improving load factor (flattening the daily load curve)

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\(^7\) PV based on assumed benefit from 2019 (full smart meter coverage) to 2025 (then superseded by responsive demand, demand side management and active network management benefits)
and hence reducing the need for network reinforcement. The effect of Active Network Management is to release network capacity headroom by optimising power flow and voltage.

Whilst it is true that Active Network Management would deliver further network capacity headroom benefits even when load factor is unity, given that achieving unity power factor is impracticable, the benefits of Active Network Management are best considered as contributing further towards the overall benefits described in the Imperial College report and (in the context of 4th carbon budget scenarios) the benefits quantified under Proactive Planning Q2 above which predicted a PV investment saving of £680m against the Imperial College report’s suggested minimum PV saving of £1.36b.

It would be reasonable to assume that Active Network Management might make further inroads towards the theoretical PV saving of £1.36b. Moreover, Active Network Management would deliver savings in conventional reinforcement in areas not considered by the Imperial College study, for example investment to accommodate the high penetrations of photovoltaics depicted in DECC’s 4th Carbon Budget scenarios.

Overall, it is reasonable to assume that a further 10% of the minimum PV saving in conventional reinforcement of £1.36b might be delivered through Active Network Management – i.e. a further PV saving of £136m.

Q2 - How much more could the DCPR5 allowance be reduced as a result of active network management (e.g. in %), over and above those due to proactive planning (row above)?

Over the DPCR5 period (which is the period over which the estimated 5% reduction in investment referred to) it is not anticipated that Active Network Management will be necessary since most LV and HV networks will have sufficient capacity headroom to accommodate the relatively low volumes of EVs, heat pumps and micro-generation anticipated up to 2015. Localised clusters might be problematic but not at a scale that would initiate wide-scale Active Network Management.

Active Network Management is most likely to become important over the second half of the RIIO ED1 period and throughout ED2 (i.e. up to 2031) during which time it is reasonable to assume that it would deliver the £136m PV saving described under Q2 immediately above.

Q3 - Are the data flows associated with active network management necessary to activate demand side management functions?

Data flows associated with functions T6.2.1 and T6.3.1 are key to Active Network Management functions; T6.2.1 in particular is an essential data flow for the purpose of active voltage control while T6.3.1 provides the means to confirm the effectiveness of the active voltage control scheme. Complementary active monitoring functions are T6.3.54, T6.3.55 and T6.3.56, T6.3.4 which, in this context, would simply provide an early warning of voltages approaching statutory limits and hence the need for an intervention, such as Active Network Management, to be considered and/or the need to begin collecting half hourly voltage data from selected meters under TS6.2.2.

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8 Again, it is important to note that this is based on the minimum NPV saving of ‘smart’ over conventional (BU) investment of £1.36b at 25% penetration levels; the maximum NPV saving being £4.47b at 25% penetration levels.
Please refer to Section 3 - ‘How Smart Meter Data would be used - Active Network Management’ above.

**Demand Side Management**

**Q4 - What benefits would result from dynamic DSM that requires remote load control, over and above the benefits estimated from the behavioural load shifting driven by STOU?**

As stated in Proactive Planning Q2 above, it is unlikely in practice that load factor could be improved to the extent depicted in the Imperial College report through responsive demand enabled by time-of-use tariffs alone. Both smart appliances and dynamic load shifting are also likely to be required, albeit that the time-of-use tariff will then provide the necessary incentive for consumers to either buy smart appliances or relinquish control over flexible electrical appliances (and EV chargers) to a third party.

T6.2.4, T6.2.5, T6.2.6, T6.2.7, T6.2.8 each describe an auxiliary switch function to control individual LCTs or other flexible demand.

T6.2.3, would be used as a backstop measure to deal with excessive demand potentially in excess of the service cable and termination rating.

In terms of benefits, the introduction of dynamic DSM through remote load control, perhaps by Suppliers (or in future Commercial Aggregators or Virtual Power Plant Operators) should significantly improve load factor and hence make further inroads towards the theoretical minimum £1.36b PV saving in conventional reinforcement as depicted by the Imperial College report at 25% penetration levels of EVs and heat pumps. Factoring in smart appliances, which could respond to price signals and hence require no direct remote control, would further enhance the contribution towards the theoretical minimum £1.36b PV saving in conventional reinforcement.

Taking the 15% contribution assumed under Proactive Planning Q2 above, it would be reasonable to assume a further 20% of the minimum PV saving in conventional reinforcement of £1.36b might be delivered by dynamic DSM through remote load control and smart appliances - i.e. a further PV saving of £272m.

Therefore, taking the combined effects of responsive demand through behavioural change, Active Network Management, dynamic DSM through remote load control and smart appliances, some 45% of the minimum theoretical PV saving of £1.36b in conventional reinforcement depicted in the Imperial College report might be delivered, leading to an overall PV saving of £612m.

**Outage Management**

**Q5 - Is there more recent data on the benefits of improving outage management (compared with DECC’s, as set out on p.36-40 of the IA)?**

The August 2011 IA assumes a customer willingness to pay value of 17p per minute of lost supply based on the DPCR5 incentive rate in turn informed by Ofgem’s 2008 customer willingness to pay survey. Whilst no ‘future scenario’ survey has been undertaken, it is apparent that the ‘inconvenience cost’ of loss of supply will increase in a future with greater reliance on electrified home heating and personal transport.

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9 Again, it is important to note that this is based on the minimum NPV saving of ‘smart’ over conventional (BU) investment of £1.36b at 25% penetration levels; the maximum NPV saving being £4.47b at 25% penetration levels.
Whilst the inconvenience to consumers of the initial interruption to supply might not change, consumers will be far more concerned over the duration of such interruptions.

This is especially relevant to the generally longer interruptions associated with LV faults which will seriously impact home ambient temperatures and the availability of hot water, and potentially leave EVs discharged and unable to provide personal transport. It follows that the need for a more rapid and efficient response to LV faults is a prerequisite to maintaining consumer satisfaction with service levels. It also follows that current assumptions over willingness to pay are almost certainly understated when considered in the context of electrified home heat and personal transport.

In terms of the August 2011 IA assumption of an achievable reduction in the average length of an LV interruption from 192 to 182 minutes, this would seem reasonable if ‘last gasp’ power outage functionality is included. Network Operators currently rely on at least two consumer calls to be made from the same discrete geographic area in order to confirm the probability of an LV network fault (a single call could indicate a problem with the consumer’s own installation, a main fuse failure or a fault on the service cable feeding his property - the energisation status check function would either confirm or discount the former).

Even during waking hours, it might take several minutes for a consumer to realise that their incoming supply has been lost (i.e. not just due to a blown fuse or circuit breaker tripping in their consumer unit). They will then generally take a further few minutes to locate the correct telephone number and make a call.

During the working day, many consumers will be away from their home, meaning that more time will elapse before a second consumer makes a telephone call. During sleeping hours (when EVs are most likely to be recharging) it is conceivable that a number of hours could elapse before a call is made to the Network Operator’s call centre. Even once the calls have been made, there will generally be a delay in ascertaining the linkage between the consumers’ addresses and the affected network and hence before a repair crew is dispatched.

The ‘last gasp’ function, by contrast, would mean that call centre staff would be immediately aware (within the latency capability of the WAN) not only of the interruption but the precise location and extent of the interruption. It is quite probable that repair crews could be dispatched before many consumers even realised that an interruption to their incoming supply had occurred. Taken all together, an assumed average 10 minute saving would appear reasonable.

Under severe storm conditions, which although relatively uncommon can result in many times the number of LV faults experienced during a normal day, the average duration of interruptions will generally be much longer than 192 minutes and, for some consumers, over 18 hours. Whilst last gasp outage detection might have limited application under storm conditions, the energisation status checking function could significantly reduce the average duration of LV interruptions under such conditions, and potentially all but eliminate over 18 hour interruptions and hence ‘Guaranteed Standard of Performance’ GS2 failures (similarly GS11A, B and C, and GS12 in the case of the Scottish Highlands).

In terms of overall benefit: based on Ofgem’s WTP valuation of 17p per minute of lost supply (which, as discussed, is probably conservative from a future perspective) - and based on the number of consumer interruptions experienced due to LV network faults, estimated to be around 3 million p.a. nationally - then reducing the average

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10 Call centres are now able to identify the approximate location of the origin of a telephone call from a land-line but not from a mobile phone
duration of interruption from 192 to 182 minutes would give rise to a benefit of £4.53m p.a. equivalent to a PV of £47.49m over the period 2015-2030.

It is acknowledged that in order for DNOs to take full advantage of earlier notification of LV faults, and for consumers to benefit from earlier supply restoration, DNOs would need to incorporate Last Gasp and energisation status data flows within their existing enterprise systems (for example GIS, network management, fault management and customer management systems) and also review their emergency repair crew dispatch procedures.

**Q6 - We recognise that a minimum coverage/critical mass of premises with outage detection are required for these benefits to be realised. What views / evidence can be provided on the threshold above which outage management benefits are generated?**

LV faults involving a single substation fuse failure (LV circuits are protected by three fuses, one for each of the 3 phases) might impact fewer than 10 consumers. (generally more in suburban areas but sometimes less in rural areas). However, ‘open circuit’ faults on LV cables could impact just a few consumers or even a single consumer; roughly 25% of LV network or service cable faults affect only a single consumer. Irrespective of how many consumers are impacted it is important to understand that the loss of supply (last gasp) signal must be generated at the point(s) of supply as otherwise it will not necessarily be possible to detect that an LV fault has occurred or that supplies have been interrupted.

In theory, once each of the three phases of each LV circuit from each and every distribution substation is covered by at least two smart meters with last gasp functionality, then a fuse failure at any substation (or an open-circuit fault) would be discernible. The number of consumers supplied by a single LV circuit from a substation will vary but will typically average between 20 and 30 (i.e. between 7 and 10 consumers per phase of a 3-phase LV cable).

It follows that a coverage of between 1 in 3 and 1 in 5 consumers would theoretically be sufficient to detect an LV network fuse failure through Last Gasp functionality provided only that the properties were carefully selected. However, this coverage would not necessarily detect an open-circuit fault, nor of course a fault affecting only one consumer (i.e. approximately 25% of all LV faults). Moreover, DNOs’ records regarding phase-connectivity might contain inaccuracies and since the rollout is to be Supplier led, Network Operators will have little control over the properties selected and how soon their networks will receive the required coverage. That said, assuming Network Operators invest in the necessary systems, then some benefits will begin to be generated from DCC go-live and will increase as smart meter coverage increases.

In reality it would be logistically impractical to equip smart meters selectively with Last Gasp functionality and this in any case would leave the great majority of consumers vulnerable to localised open circuit or service cable faults going undetected.

**Q7 - Which instances of dis-enablement of supply do the messages 13, 14, and 15 refer to? Outage detection will not trigger a message in the case of dis-enablement at meter point, so is the purpose of messages 13, 14, and 15 to implement demand-side management measures or to fix faults? What additional incremental benefits would result from receiving confirmation that a dis/enablement at meter point has been successful (i.e. of having messages 13, 14, 15)?**
T6.3.41 provides the capability for the Network Operator to disable the supply to a consumer; T6.3.52 and T6.3.53 respectively confirm that the supply has been disabled / re-enabled (restored). The purpose of this functionality is to enable the controlled restoration of supplies following a fault or potentially following a load reduction action by a Network Operator.

It is a known and well understood phenomenon that when supplies are restored following an interruption (especially following a prolonged interruption) that the load appearing on the network at the time of restoration will be higher than immediately before the interruption, and potentially higher than at any time prior to the interruption. This phenomenon is known as ‘cold pick-up’ and occurs because appliances that would normally be cycling (such as refrigerators and freezers) and any load that is thermostatically controlled, will immediately consume electricity on re-energisation and continue to do so until normal cycling resumes and diversity is restored. The immediate impact on re-energisation of domestic appliance motors (which generally have much higher staring currents than their full load operating current) can be particularly problematic. This includes washing machines, tumble dryers, refrigerators, freezers and central heating hot water circulation pumps.

In future, this phenomenon will become far more acute. This is because there will also have been some loss of diversity in EV charging and thermostatically controlled heat pump load. Indeed, the combined effect of several heat pumps starting simultaneously could be particularly problematic (starting currents can be several times the magnitude of steady-state currents). Moreover, demand normally supplied by any installed micro-generation (so-called latent demand) will be picked up by the network on re-energisation since the micro-generation will have automatically shut down on loss of incoming supply.

It follows from the above that on networks with high volumes of EVs, heat pumps and/or micro-generation, post interruption re-energisation will in future need to be a more controlled process, possibly involving staged restoration. This is the purpose behind the functionality covered by T6.3. T6.3.52 and T6.3.53. This functionality would also allow partial restoration of consumer supplies from an alternative (but limited capacity) source, for example while a faulted cable is being repaired, and potentially a more selective means of rota disconnection (i.e. during transmission system emergencies or temporary serious shortfalls in generation capacity) for example to protect vulnerable customers.

Q8 - DECC has quantified improved customer service in terms of reduced customer minutes lost (CML). What additional benefits would be associated with improved customer service, over and above this?

The IA does not place any value on improved customer service following an interruption in supply, i.e. in terms of not having to make a telephone call and/or if a telephone call is made being able to speak to a call centre agent who is already aware of the problem and able to reassure the consumer that the repair crew are already on the way.

Ofgem currently commissions customer satisfaction surveys related to consumers’ experiences in contacting call centres following a supply interruption. It is clear that consumers place great value on speed of telephone response, willingness to help, and on receiving accurate and helpful information regarding both the cause of the interruption and the anticipated duration of the event.

With the benefit of last gasp outage detection, call centre staff would have more accurate information as to the cause and extent of the fault and the likely duration of the interruption, and be in a position to advise consumers that the problem is already
known and that a repair crew is about to be (or has already been) dispatched. They will also generally be able to provide an ‘ETA’ for the crew to arrive on site which will be particularly reassuring to consumers. Alternatively, of course, the consumer might simply feel that no call is necessary, knowing that the Network Operator will already be aware of the problem, and hence not be inconvenienced through having to find a telephone number and then make a call. A reduction in call volumes would in turn improve the speed of telephone response (i.e. the time taken to speak to an agent for those consumers making a call) due to reduced queuing.

There would also be benefits in terms of reduced ‘Guaranteed Standards of Performance’ failures. Guaranteed Standards of Performance GS1, GS2, GS2A and (in severe weather conditions) GS11A, 11B, 11C and 12 (the latter applies to Scottish Highlands only) are all concerned with restoration times following supply interruptions. Accurate recording of Guaranteed Standards of Performance failures would be a secondary but important customer service benefit. At present, apart from GS1, consumers have to claim GS failures, which then have to be verified (albeit in the absence of reliable information - for example as to when precisely the supply failure occurred). The availability of time-stamped interruption and restoration logs (associated with T6.3.9 and T6.3.50) would enable accurate recording and give rise to the possibility of automated Guaranteed Standards payments.

Whilst GS payments made by DNOs vary significantly year on year, taking 2008/09 as ‘typical’ year (payments in 2009/10 were 172% higher for GS1 and 47% higher for GS2) the payments across all DNOs for the relevant Guaranteed Standards were as follows:

<table>
<thead>
<tr>
<th>Guaranteed Standard of Performance</th>
<th>No. Payments</th>
<th>Total Paid</th>
</tr>
</thead>
<tbody>
<tr>
<td>GS1 (main fuse failure)</td>
<td>101</td>
<td>£2,020</td>
</tr>
<tr>
<td>GS2 (interruption over 18 hours)</td>
<td>11,237</td>
<td>£556,600</td>
</tr>
<tr>
<td>GS2A (multiple interruptions)</td>
<td>842</td>
<td>£42,100</td>
</tr>
</tbody>
</table>

With reference to Q5 above, should it be possible to ‘all but eliminate’ GS2 payments then the saved payment benefit would be around £0.5m p.a. But of course, by far the greater benefit would be in terms of improved customer service.

Messages

Q9 - What are the current costs of notifying a customer of an event (e.g. number of occurrences per year; and postage costs; complaints)? How will these costs be affected by the messages 19, 20?

Based on Ofgem’s DPCR5 targets for DNO planned interruptions, on average\footnote{It would be more accurate to use a weighted average but this is sufficiently representative to address the question}, each DNO will interrupt approximately 7% of its consumers each year due to a planned interruption (though the targets vary widely across DNOs). If 7% of all consumers are notified of an interruption each year, that would amount to approximately 2 million consumers p.a.
DNOs are required by law to provide consumers with 48 hours’ notice of a planned interruption. Such notification is generally undertaken by post or hand delivery. Based on the first class post charge rate of 46p this is equivalent to approximately £1m p.a.

It is therefore conceivable that £1m p.a. (equivalent to a PV saving of £8.6m) across all DNOs could be saved if notifications through the smart meter and IHD were possible. This function is described by T6.3.2. However, this would require secondary legislation (i.e. an amendment to the Electricity Safety Quality and Continuity Regulations) to permit notification by telecommunications as opposed to ‘in writing’. Moreover, the method would be reliant on the IHD being functional (and read by the consumer).

In practice, it is unlikely that smart meter messaging will displace written notifications of supply interruptions in the foreseeable future. However, the messaging could usefully supplement the written notification. Sometimes, postal notifications are mistaken for ‘junk mail’ and discarded, and due to inaccuracies in postal address information, premises might sometimes be missed. Smart metering messaging could therefore provide a back-up notification service.

A further benefit would be to inform consumers at short notice of any late changes to the planned interruption - for example revised timings or cancelations (e.g. due to bad weather or problems on an adjacent network). This function is described by T6.3.27

More imaginative uses of the messaging capability could include: warnings of planned street works or road closures for electricity (or gas) works; severe weather warnings likely to affect supplies; maintenance works that might cause a temporary reduction in voltage due to alternative feeding arrangements; and urgent emergency works that need to be undertaken without advance written notification.

It is understood that Suppliers will also require messaging facilities.

**Voltage Problems**

**Q10 - What costs are currently incurred as a result of damages to consumer appliances or wiring? How much avoided costs can be reasonably expected from having this (floating neutral protection) functionality?**

DNOs incur costs in the region of £5m p.a. (equivalent to a PV saving of £43.1m) to settle claims associated with extreme voltage excursions. This type of network fault, whilst relatively rare, can cause significant damage to consumers’ installations and appliances, the cost of which is also reflected in insurance claims and premiums and hence is not fully reflected in the above DNO incurred expenditure. Moreover, the disruption to those affected can go beyond the more typical fault scenarios where customer ‘recovery time’ is relatively quick. When consumers’ installations are damaged under neutral fault conditions material damage to their property can occur.

There are two main scenarios where this condition manifests itself:

- Where the neutral connection is broken as a result of a cable failure or increasingly due to theft of copper neutral / earth conductors from substations. A DNO might currently experience several incidents each week where copper theft occurs.

- A gradually deteriorating situation of the low voltage underground cable such that the neutral impedance increases over time.
In both these scenarios, depending on the varying balance between the load conditions on each of the three phases, high or low voltages can be experienced by customers ranging (theoretically) between 440V and 0V.

Notwithstanding the obvious distress caused to consumers by these incidents, these events also have the capacity to give rise to serious injury. The potential £5m p.a. saving therefore does not fully reflect the value of removing this hazard through the smart meter self-disconnecting once a configurable high voltage threshold is detected.

T6.3.4 describes the alarm functionality (but note that this is a specific variation to the alarm function for notifying Network Operators on a non-urgent basis of voltage limits approaching statutory limits; these two functions being separately identified in IDTS).

T6.3.49 simply notifies the Network Operator that voltage has returned to within the alarm threshold limits.

The ENA proposal is that under extreme high voltage conditions (the threshold would be configurable) the smart meter internal switch would open, performing a similar function to that described by T6.2.3 except in this case the trigger would be high voltage rather than high load. If floating neutral protection were to be included, it is reasonable to assume that it would if greatly reduce, if not eliminate, damage to consumers' electrical installations and appliances.

Meter Configuration

Q11 - What settings will need to be reconfigured? How often will they need to be reconfigured? Which settings require “on demand” reconfiguration?

T6.3.39 refers to temporary reconfigurations that might occasionally be required to be implemented at short notice; for example temporary suppression of alarms such as voltage sag and swell alarms during storm conditions.

T6.3.40 provides the capability to change threshold settings e.g. for high / low voltage alarms and to selectively enable smart meters to provide an installed function. An example of the latter would be to activate function T6.2.1 to provide data to a local voltage control scheme.

Neither of the above functions would create significant data flows as their use would be infrequent. Indeed the ability to activate / deactivate data flows and alarms would have the effect of reducing data traffic over the WAN. Suppliers will also require the capability to reconfigure smart meter functions and it is not anticipated that the functionality required by Network Operators will increase the required capacity of the WAN.

Network Losses

Q12 - What is the latest evidence regarding how much smart meters would reduce network losses? How is this expected to evolve over time?

Losses essentially fall into two camps: technical and non-technical losses. Dealing first with the latter, non-technical losses are those associated with inaccuracies in meter readings or estimated consumption (i.e. especially as meters are no longer read every quarter - although these errors should eventually self-correct) unsettled
consumption (i.e. units consumed but missed out of settlement), meter errors, and theft.

The ability for consumption to be recorded accurately by the smart metering system should all but eliminate errors due to estimated and missed reads - which currently appear as losses. Improved tamper alerts might also reduce theft although, conversely, in the absence of visits by meter readers, evidence of attempts to steal electricity through by-passing or other forms of corrupting the meter register might go undetected.

Of greater interest from an overall energy efficiency and carbon impact perspective is that of technical losses\[^{12}\]. Electrical losses are estimated to be currently responsible for 1.5% of GB GHG emissions (although this impact will obviously reduce as electricity generation is gradually decarbonised). DNOs have a regulatory incentive to reduce losses (the DPCR5 incentive rate is £60 per MWh pre-tax - no differentiation is made between technical and non-technical losses). Technical losses fall into a further two camps: fixed (or iron) losses and variable (or copper) losses.

Fixed losses (mainly associated with transformers in the form of hysteresis and eddy current losses) will by definition not vary with energy distributed or peak demand growth; such losses are more or less constant and are incurred continuously whilst the transformer is energised\[^{13}\]. Variable losses are due to electrical resistance in conductors and are proportional to the square of the electrical current (or energy) passing through a conductor (for example a cable, overhead line or transformer winding).

Approximately 30% of technical losses will be due to fixed losses and 70% due to variable losses (though, again, there will be regional variations in this ratio). By voltage level, some 55% of fixed losses will be due to HV/LV distribution transformers and 20% due to EHV/HV transformers; 45% of variable losses will be at LV network level and 25% at HV (generally 11kV) level. Overall, LV losses account for around 45% of total losses and HV losses account for around 25%. EHV losses account from around 25% of fixed losses, 30% of variable losses and 30% of losses overall.

A reasonable assumption is that overall, technical losses for distribution networks are currently around 5% of the electrical energy distributed. Given the current GB annual electricity energy demand of around 350TWh, and assuming 5% technical losses (i.e. net of non-technical losses) for distribution networks, the current level of technical losses is approximately 17.5TWh p.a.

Being a function of energy growth, peak demand growth, load factor, network architecture, network capacity and the rate at which older high iron loss transformers are replaced with lower iron loss units, there are many factors which could impact on network technical losses over the period to 2030. However, assuming that conventional load growth remains net neutral - i.e. natural load growth due to increased population, employment growth and additional housing is countered by higher efficiency-rated electrical appliances, higher energy prices (leading to reduced consumption) and energy efficiency generally - then the additional demand presented to networks (gross of any offset due to DG or micro-generation) would be mainly that due to electrification of heat and transport.

Taking DECC’s 4\[^{th}\] Carbon Budget scenarios to 2030, and depending on the individual EV and heat pump growth scenarios chosen, EVs could present up to an additional 16.6TWh of demand while heat pumps could present up to an additional

\[^{12}\] In this respect, it should be noted that the combined consumption of smart meters and their associated communications hubs - i.e. meter losses - will exceed that of dumb meters.

\[^{13}\] Fixed losses do however vary with voltage; a 1% increase in secondary voltage typically produces a 2.5% increase in fixed losses.
DECC’s 4th Carbon Budget scenario 3 would result in both of these additional demands being presented to distribution networks and almost entirely at the LV network level. On that basis, national electricity energy demand would increase to 416TWh, i.e. an increase of 19% compared with today.

In the absence of investment in additional capacity, the impact of an additional energy demand of 49.5TWh on LV network variable losses alone would be to cause an increase from \((0.45 \times 17.5) = 7.85\)TWh to \((0.45 \times 17.5 \times 1.19^2) = 11.15\)TWh.

In practice, it would not be possible to accommodate this level of additional demand on LV distribution networks at current load factors without significant reinforcement. With reduced load factors (i.e. ‘peakier’ demands) then capacity headroom would be further reduced and losses would increase further.

The effect of electrification of heat and transport on distribution network losses is complex. Higher levels of electrical energy distributed through the network due to EVs and heat pumps will increase variable losses in absolute terms (albeit DG and micro-generation will generally reduce losses provided there is a reasonable level of local load matching).

However, if daily load profiles become more ‘peaky’, e.g. due to EV charging and heat pump operation in the winter weekday early evening period (when demand already peaks), then network variable losses will increase disproportionately to the energy distributed.

For the reasons outlined earlier in this paper, a key objective of smart grids facilitated by smart meter data is firstly to prevent a degradation of load factor arising from EVs and heat pumps which might naturally draw energy from the distribution network at times of peak demand, thereby increasing peak demand disproportionately to the increase in energy demand; and secondly to improve load factor through peak shifting. Typical annual load factors on LV and HV networks will be around 0.35 to 0.4 and 0.45 to 0.5 respectively.

The main objective of maintaining or improving load factor is to preserve network capacity headroom and hence minimise the need for capacity investment. However, responsive demand enabled through time-of-use tariffs coupled with smart appliances and/or active control of flexible demand also has the potential to mitigate a disproportionate increase in variable network losses (including upstream transmission losses) by encouraging consumers to avoid peak demand periods as far as practicable.

The chart below indicates the theoretical potential for responsive demand (DSM) to reduce or maintain variable losses on an LV network at the current level while accommodating an increase in demand. The figures assume improvements in daily load factor consistent with the Imperial College report.

The chart indicates that DSM has the potential to reduce LV network losses by 0.28 percentage points based on current levels of demand while an additional 17% of energy demand could be accommodated without any increase in LV network (variable) losses (in terms of percentage of energy distributed). Active Network Management techniques designed to optimise voltage and power flows, and enabled by smart meter data, will also have a beneficial impact on distribution networks losses.

Given the above scenario whereby national electrical energy demand increases by 19%, then the chart indicates that, by realising the full potential of responsive demand (DSM), losses on LV networks (as a percentage of energy distributed) would increase only marginally (by around 0.05 percentage points).
It follows that, in theory, even given the 19% increase in energy demand associated with DECC’s 4th Carbon Budget scenario 3, DSM has the potential to minimise the need for network investment in capacity while maintain LV losses at a roughly constant level (i.e. an increase of around 0.05 percentage points)\textsuperscript{14}.

Assuming that LV losses account for 45% of total losses (from above), the level of LV network losses required to deliver a 19% increase in energy demand assuming the level of DSM depicted in the above chart (and with the requisite degree of network reinforcement) would be 0.45 x 17.5 / 1.05 = 7.44TWh.

Comparing this with the level of LV network losses without DSM of 11.15TWh (from above) this equates to a saving in losses in percentage terms compared with the counterfactual of (11.15 − 7.44 / 416) = 0.9%. Taking the current valuation of losses at £60 per MWh, the value of DSM in terms of losses reduction is (11.15 - 7.44) x 60 x 10\textsuperscript{6} = £223m p.a.

In practice, this saving will be dependent on the degree to which the level of DSM (responsive demand) assumed in the Imperial College report is deliverable. In the event that only 45% of the benefit assumed in the Imperial College report is deliverable (as per the assumption under Demand Side Management Q4 above) then from the above chart it can be inferred by extrapolation that LV losses with a 20% increase in demand might increase by around 0.6 percentage points above the level achievable under the ideal load shape - i.e. 0.006 x 416 = 2.50TWh, reducing the losses benefit (compared with the counterfactual) to (11.15 - 7.44 - 2.5) x 60 x 10\textsuperscript{6} = £121m p.a. (i.e. rising to this level at 2030).

On that basis, the saving in losses at 25% LCT penetration level, assuming 35% progression towards the Imperial College report ‘ideal’ load factor through voluntary responsive demand (incentivised through time-of-use tariffs) and demand side management (through remote load control and/or smart appliances) plus a further 10% benefit through active network management (of power flows and voltage levels) then the saving in LV network losses compared to the LV network losses incurred in the absence of responsive demand, demand side management and active network management would have a \textbf{PV of £528.1m}\textsuperscript{15}

\textsuperscript{14} Note: this would still entail a level of investment in network capacity as per the Imperial College report 20% penetration scenario.

\textsuperscript{15} This is based on an assumed LCT take-up pattern consistent with DECC’s 4th Carbon Budget scenario 3 for electric vehicles and heat pumps.
6. Summary of Monetised Benefits

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<thead>
<tr>
<th>Category</th>
<th>Nature of Benefit</th>
<th>Annual Benefit £m</th>
<th>Present Value £m*</th>
<th>Notes</th>
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<tr>
<td>Proactive Planning of HV &amp; LV networks</td>
<td>Better informed load-related investment decisions</td>
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<td>From 2019-2025 only - then superseded by Responsive Demand and ANM benefits</td>
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<td>Responsive Demand - TOU tariffs</td>
<td>Reduced need for network capacity to meet peak demand</td>
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<td>Voltage monitoring and sag/swell alarms</td>
<td>Avoided voltage complaints and admin costs</td>
<td>1 (i.e. rising to this value by 2030)</td>
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<td>Assume gradual increasing trend from 2015 to 2020 due to increasing smart meter volumes and from 2025 due to faster LCT ramp rate and full smart meter coverage</td>
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<td>Reduced investment to serve new connections</td>
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<td>Reduced postal / transport charges</td>
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<td>Requires changes to ESQC Regs to realise benefit</td>
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<td>Extreme Voltage Protection</td>
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<td>Management of Network Losses</td>
<td>Reduced increase in LV network losses due to improved load factor (linear rate of increase to 2030)</td>
<td>121 (i.e. rising to this value at 2030)</td>
<td>528.1</td>
<td>Based on DECC scenario 3 (19% increase in distributed electrical energy to 416TWh at 2030) – assuming losses valued at £60 per MWh (2012)</td>
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| Total Present Value | 1,292 | Equivalent to £46 per electricity smart meter |

*based on 3.5% real annual discount rate; no benefits beyond 2030 are accounted for.

**Imperial College study applied 3.5% real annual discount rate to derive present value.
## 7. Discounted Cash Flow Tables

### Proactive planning

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### Reduced LV fault customer interruption time

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### LV network losses

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