ENA High Level Smart Metering Cost Benefit Analysis

For: Energy Networks Association

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Engage Consulting Limited

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Executive Summary

The approach followed in deriving the cost benefit analysis in respect of the ENA Requirements is described in the next section. The key starting point for this analysis is a comparison of the ENA requirements against the ERA SRSM updated requirements in order to accurately identify which requirements within the ENA specification are truly incremental to (as opposed to duplications of, or minor variations on) the SRSM specification. This cost benefit analysis is based on these assessed incremental requirements.

While each of the individual elements of this cost benefit analysis has been developed as an individual product, this report summarises the results across the main categories.

The project then used the identified incremental ENA requirements and compared them to the information provided by BEAMA member Meter Asset Providers aiming to derive the cost of each requirements. The additional cost of providing the firm (non-optional) ENA requirements within the meter specification is expected to be in the region of £0.60 - £1.10 for electricity meters and £0 for gas meters (the latter on the basis that calorific value will not be calculated by the meter). There are additional optional requirements that could increase the cost of the electricity meter by c. £1.50 - £7. However, while some or all of these requirements could still be justified subject to further exploration of the range of costs estimated by the MAPs, for the purpose of this CBA the functionality is assumed not to be justified at this stage and neither the benefit nor the cost is therefore included in this analysis.

The next step of the project consisted of the Data Traffic analysis, which identified common ERA/ENA and ENA only data flow. The analysis suggests that in considering the total estimates of data flow for ENA related functionalities, the proportion of common ENA and ERA related data to support both network planning and ToU tariffs is in the region of 12-15% for total data traffic for gas and electricity meters per year. However, this figure could increase significantly if it is assumed that suppliers will also eventually require more granular consumption profiles e.g. half hourly energy consumption profiles Since the results of this aspect of the analysis cannot be incrementally costed at this stage due to current uncertainties within the smart metering rollout and communications architecture policies that are to be adopted, this aspect of the analysis is provided in terms of incremental traffic for use in the Ofgem and DECC cost model.

The further step of the analysis provided high-level identification of the potential scale of developments to DNO systems and processes necessary to accommodate smart metering data (both for routine billing of consumption, and for network management purposes)., This part was not quantified at this stage as the scope of such developments will be dependent on the ultimate design of the central communications system. Such developments will be informed by any pilot stages of the smart metering roll out programme (including any interim arrangements if the programme is brought forward) and potentially from the findings from Low Carbon Network Fund trials (the latter being particularly relevant to network management and smart grid developments).

After the costs have been identified, the project followed then with the identification of benefits of functionalities required by the ENA members. The benefits arising from the ENA incremental requirements have been quantified where possible and have been derived from a high level analysis of the benefits associated with improved operational management and network planning information following the approach described in the DECC Impact Assessment.

For the reasons outlined above, the analysis would be impacted by further consideration of costs which are dependent on the central communications solution and which therefore cannot yet be quantified (such as those that might be necessary to manage the increase in data traffic and the enhancement of DNO information management systems). On the other hand the analysis does not include 'intangible' benefits as identified in the DECC IA and ENA Use Case analysis such as an improved customer service experience.

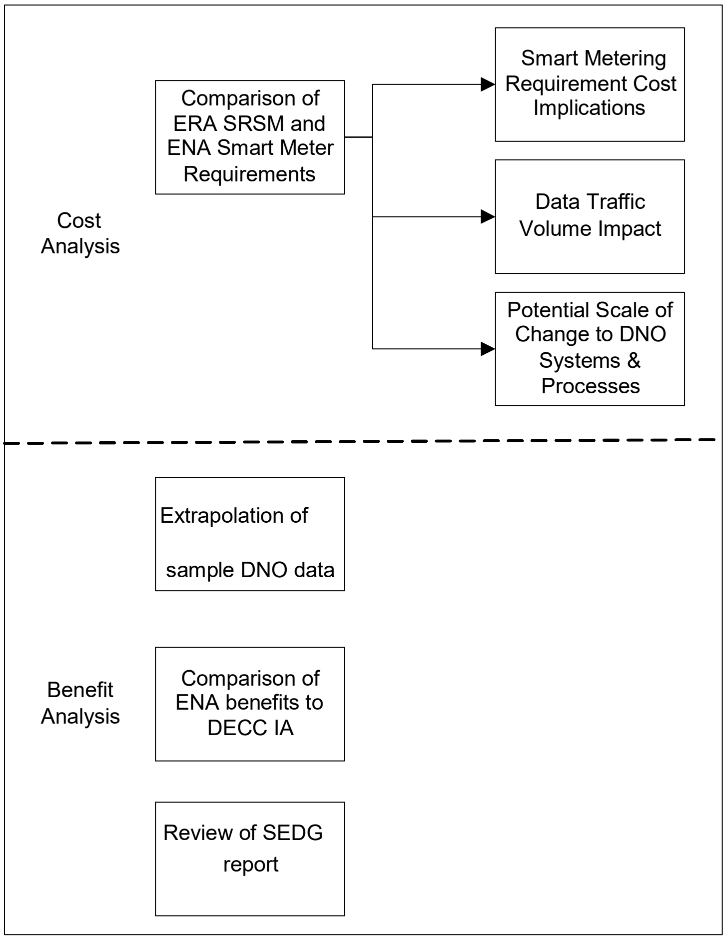
While this analysis considers the 'business as usual' network management benefits that would accrue from the availability of smart metering data, it is important not to lose sight of the 'several orders of magnitude' higher level of benefits that would accrue in the likely event that, during the lifetime of the first generation of smart meters and systems, there is a significant take up of electric vehicles and/or heat pumps. The SEDG report for ENA "Benefits of Advanced Smart Metering for Demand Response based Control of Distribution Networks", highlights the potential avoided cost of HV and LV network reinforcement if smart metering systems can be used as an enabler for the application of responsive demand solutions. The report estimated the potential avoided distribution networks reinforcement costs to be in the range of £0.5bn to £10bn (NPV), depending on electric vehicle and heat pump penetration levels, the degree of responsiveness of the associated demand, and the range of network reinforcement solutions that might be required.

On the basis of the analysis described above, the results of the **cost benefit analysis shows that the incorporation of the ENA incremental requirements gives rise to a positive net present value of c£50m** (based on a 20 year assessment to align with the DECC IA timescales).

1.1 Approach Followed

The diagram below describes the approach followed in the Cost Benefit Analysis.

Diagram 1 – Key activities of CBA



1.2 Introduction to Activities

These activities provide the ENA with a high-level Cost Benefit Analysis and an assessment of the network specific requirements of smart metering. These also provide rationale to support the work undertaken to date in the ENA smart metering project and can be used in sharing the high-level Cost Benefit Analysis with Ofgem.

The cost analysis looks at:

- A Comparison of ERA SRSM and ENA Smart Meter Requirements;
- The Extra Network Smart Metering Requirement Cost Implications Using BEAMA Cost Estimations;
- Data Traffic Volume Impact; and
- The Potential Scale of Change to Network Operator Systems & Processes.

The benefit analysis looks at:

- A Benefit Analysis for the CBA Model;
- ENA member functionality benefits in addition to benefits identified in the Government's impact assessment published in December 2009; and

- Review of Imperial College and SEDG Report “Benefits of Advanced Smart Metering for Demand Response based Control of Distribution Networks” and Explanation of its Rationale for Cost Benefit Analysis.

This report provides an overview on and the results of each activity.

Document Control

Authorities

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1.0	9th July 2010	Craig Handford	Reviewed comments and changed document to final
1.1	12th July 2010	Craig Handford	Changes as per Dave Openshaw note 12th July
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Related Documents

Reference 1	
Reference 2	

Change History

Version	Change Reference	Description
1.0		Initial Version
1.1		Changes after comments received

Distribution

Recipient 1 Energy Networks Association
Recipient 2

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2 Introduction

This report details the high level cost benefit analysis undertaken in respect of the "ENA Smart Metering System Requirements Update". The benefits considered are those which would accrue even in the absence of 'smart grid' solutions, while the costs considered are those associated with functionality that is incremental to the SRSM requirements. The analysis does not consider the very much greater benefits of avoided network reinforcement that would accrue from the application of responsive demand solutions to minimise the impact of significant penetrations of electric vehicles and heat pumps (which is the subject of a separate report by SEDG: "Benefits of Advance Smart Metering for Demand Response based Control of Distribution Networks").

2.1 Purpose

The objective of this study has been to identify the incremental costs of the ENA Requirements (over and above the SRSM requirements) alongside the additional network operational and planning benefits (other than those associated with the application of responsive demand / 'smart grid' solutions) and evaluate the resulting cost-benefit in NPV terms. The positive NPV outcome provides further evidence to DECC and Ofgem E-serve of the justification for incorporating the ENA Requirements into the final specification for the proposed national smart metering system.

2.2 Copyright and Disclaimer

3 Cost Analysis

3.1 Comparison of ERA SRSM and ENA Smart Meter Requirements

This analysis provides a comparison of the SRSM and ENA smart metering requirements. The document outlines common SRSM/ENA specifications, unique ENA specifications (that are also over and above the scope of the DECC Smart Metering Impact Assessment), ENA requirements that add extra costs and discusses some issues and questions relating to requirements under the review.

Engage Consulting has conducted detailed analysis of the latest available requirements documentation from the SRSM project prepared by the Energy Retail Association and the Smart Metering work prepared for the Energy Networks Association.

This analysis has compared the meter specification requirements to identify:

- Requirements that appear to be common to both specifications;
- Requirements that are unique to the ENA specification, and are therefore reasonably assumed not to be within the scope of the DECC Impact Assessment which defined metering functionality at a very high level;
- ENA requirements that are perceived as adding cost; and
- Issues and questions relating to requirements that could affect the cost/benefits assessment – recorded as 'With Notes' in the table below.

Area	Total ENA Req's (1+2)	Common ERA/ENA (1)	ENA Only (2)	ENA Adds Hardware Costs	ENA Adds Meter Data Storage Costs	With Notes	Optional Requirements
Electricity	**46**	14	32	2	4	4	4
Gas	**12**	7	5	0	0	2	1
Communications	**9**	8	1	0	0	1	0

From the table above it can be noted that additional Gas network requirements do not add further hardware or meter data storage costs, as they are all utilising existing hardware or functionality. Meanwhile, for electricity, there are 2 requirements that could add hardware to the meter specification:

DNO 02.02	Measure import/export reactive energy
DNO 04.04	Record Half Hourly average RMS voltages

The table also highlights 4 requirements that could require additional cost to support data storage in the meter itself:

DNO 02.02	Measure import/export reactive energy
DNO 02.04	Capable of calculating and reporting power factors
DNO 04.11 (includes 04.04, 04.12, 04.13)	Meter will store voltage profile data for 3 months
DNO 05.02 (includes 08.03)	Store loss of supply information for configured period

Within the ENA requirements document there are several requirements seeking to store voltage information, and several looking to store Loss of Supply information for different use cases – these have been combined as indicated. In fact, from half hourly voltage profiles it should be possible to determine some power quality issues and Loss of Supply events. This consolidation would require further discussion of the requirements.

Increments to meter memory to meet these data storage requirements will add to the cost of the meter, but this is believed to be in the order of pence rather than pounds.

The ENA specification includes four 'optional' requirements. These could all add significant cost to the solution if required for every meter, as shown below.

DNO 02.10 & DNO 02.11	External / In Built Temperature Sensor
DNO 05.03	Issue alarm on detection of loss of supply
GDN 02.07	Measure and store Calorific Value

It is also anticipated that these requirements would require further detailed discussion and specification.

A further optional, requirement DNO 04.02, relating to Reverse Polarity, is not believed to be possible within GB metering, and would require external hardware with significant cost implications. This requirement is therefore not considered in detail in this analysis.

A separate paper (ENA Smart Metering Requirement Cost Implications Using BEAMA Cost Estimations) has been produced in addition to this paper to identify the potential incremental costs of the ENA smart meter functionality.

3.1.1 Specifications Reviewed

The documentation used to complete this analysis includes the following:

Document	Version	Date
SRSM Metering System Requirements	2	October 2009
ENA Smart Metering System Requirements Update	1	April 2010

This analysis compared the 120 requirements in the SRSM specification to the 58 requirements in the ENA specification and highlighted those ENA requirements that could possibly add cost or ambiguity to the SRSM 'base case' gas and electricity smart meters.

A full table of the ENA requirements, highlighting ERA coverage and any questions or notes, is appended to this document. Additionally, specific requirements are listed throughout this document, to support a certain statement or detailed discussion.

3.1.2 Anatomy of a Smart Meter

To complete this analysis, the following assumptions about the cost of a gas or electricity smart meter have been used:

- A smart metering system will typically include the following elements and components in order to operate as a smart meter:
    - Robust, secure construction and casing, in accordance with relevant standards;
    - Connections to network supplies and demand side systems – i.e. connector blocks and pipes;
    - Metrological hardware;
    - Communications hardware, to link the metering system to both remote Authorised Parties and to relevant capable devices within premises;
    - 'Operational' hardware – the microprocessor(s), memory chips and other components needed to operate in a 'smart' manner;
    - Sensors for safety and tamper purposes;
    - A display and user interface forming part of the meter itself;
    - For electricity meters, a switch (or switches) to support the enablement or disablement of supply; and
    - For gas meters, a battery.

- The ERA SRSM specification further adds the following requirements
    - For gas meters, a valve to support the enablement and disablement of supply;
    - For electricity meters, a backup battery to support operations in the case of power outage;
    - Requirement to support the minimum level of memory capacity, battery life for gas meters etc; and
    - A separate communications box to provide a single WAN connection to support both meters if present in premises .

With the exception of the valve, which remains subject to clarification from DECC/Ofgem, the SRSM specification is seen by industry participants as the de facto basis for GB smart metering and a reflection of the costing used by DECC in the preparation of the Impact Assessment.

3.1.3 More than Functionality and Meter Hardware

When assessing any incremental costs or benefits from supplementing the SRSM specification for smart metering, one needs to take account of more than just the purchase cost of a metering system.

Some functional requirements will indeed add hardware components and increase the cost of the metering system but not necessarily the meter itself. Some may result in existing hardware being upgraded and therefore adding cost. These are covered in the discussion of the ENA requirements for electricity and gas meters below.

What is not covered by this assessment of hardware is the impact of the ENA requirements on how the metering systems are used. These requirements will result in more data being collected and communicated by (and to) smart meters. The estimate of volumetric data requirements has been provided in ENA data traffic analysis. Additionally, a separate paper within the ENA Smart Metering Cost Benefit project "ENA Cost and Benefit Analysis: Data Traffic Volume Impact" assesses common ENA/ERA interest in data thus also providing a view on additional requirements for data storage and communication need from the ENA specific requirements.

At present, it is not known whether the WAN communications solution will introduce charges for usage – i.e. a 'per kilobyte' cost. If it does, evidently there will be additional cost resulting from the ENA data traffic, as this will result in more data being collected and transmitted from every meter.

If there is no 'per kilobyte' charge for data (for example, a flat subscription charge), there may still be capacity/capability costs from establishing sufficient WAN (and system) bandwidth to cope with the additional traffic resulting from the ENA requirements.

Additionally, however the data traffic is managed, the ENA requirements will result in more data being collected from meters, and this data will need to be stored somewhere in order for it to be utilised – the additional storage hardware itself will add cost, as will a software solution to enable access to the data.

This will add cost to a central role if that is where the data will be stored, or add costs to individual participants if they have to store the data and the additional capacity will need to be assessed. It is likely to add costs to many participants, central and distributed, as they will all process and store increased amounts of data.

Much of the data that the ENA requirements will produce is new. Unlike Suppliers, where smart meters will generate 'more' meter reads to go into an existing billing process and system. The network businesses will typically need to develop new data systems to cater for power flow data and these systems will need to be able to accommodate the relatively small amount of additional voltage data for every meter on their network at the types of intervals being proposed in these requirements.

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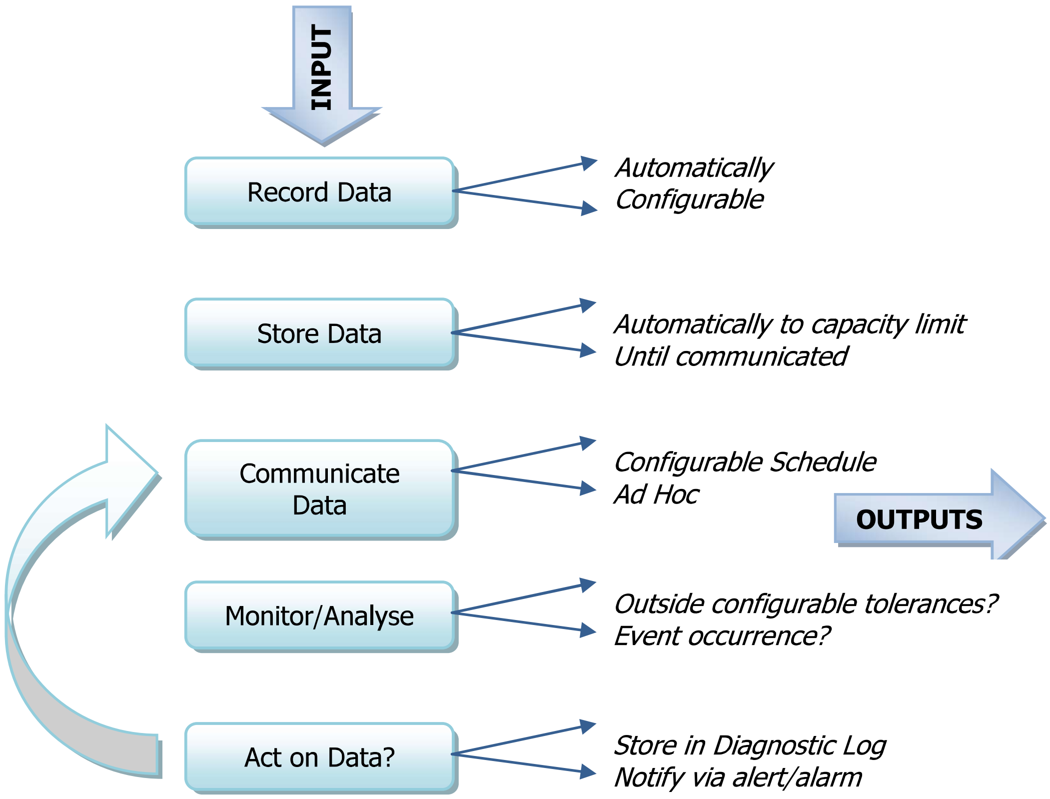
In addition, the ENA smart meter data traffic analysis completed by Engage Consulting also includes ENA member views on the required meter response time to deal with the commands and certain operations, which might add further cost to the meter requiring it to deal with potentially significant volumes of data within a small timeframe.

3.1.4 Different Requirements – Similar Functionality

Throughout the ERA and ENA requirements specifications there are specific operational requirements for data items to be recorded, stored and notified to remote Authorised Parties (or other devices). Whilst these may appear to relate to very specific business situations, at an architectural level they are fundamentally the same.

As shown below, the operations of a smart meter are relatively generic. The inputs could come from sensors or metrology or other hardware elements – these elements vary by the ERA and ENA Specifications. The outputs could go to a HAN radio, the WAN modem or to a customer display – these are common to both ERA and ENA.

These different process steps are all generally configurable – some will default to specific settings according to the requirements – but, overall what the meter does with data follows a similar process.

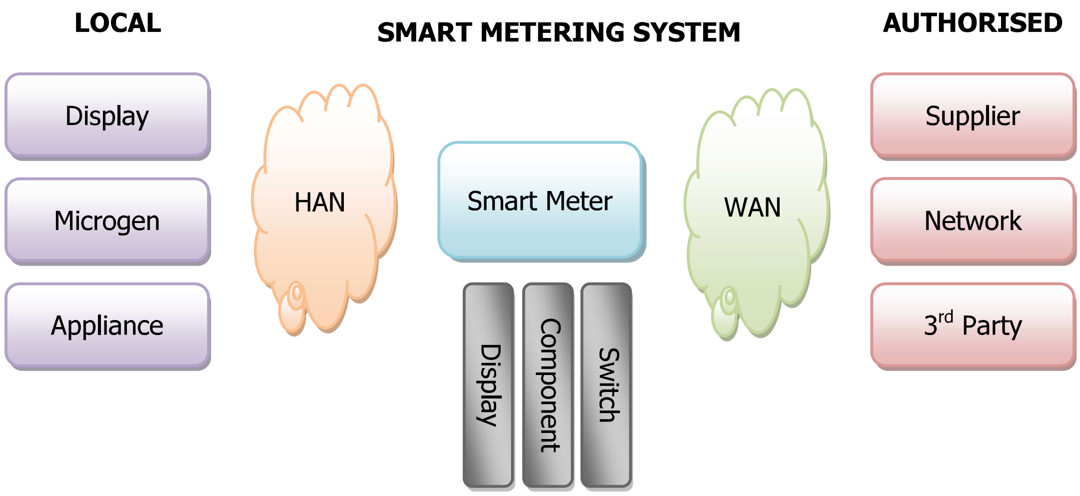


The meters need to be equipped with processing capability to manage the number of inputs and the administration of the configurable rules, and enough memory capacity to meet the requirements.

A large number of the functional requirements in both requirements documents would be met by the smart metering system that included hardware capable of supporting these processes. The SRSM specification includes requirements to support these processes, therefore any ENA requirements that make use of these processes are seen as not adding any incremental cost to the meter specification.

Similarly, there are a number of specific requirements about messaging and notification. Once again, these reflect business context, rather than actual functional activities that might require additional hardware, and can also be viewed generically.

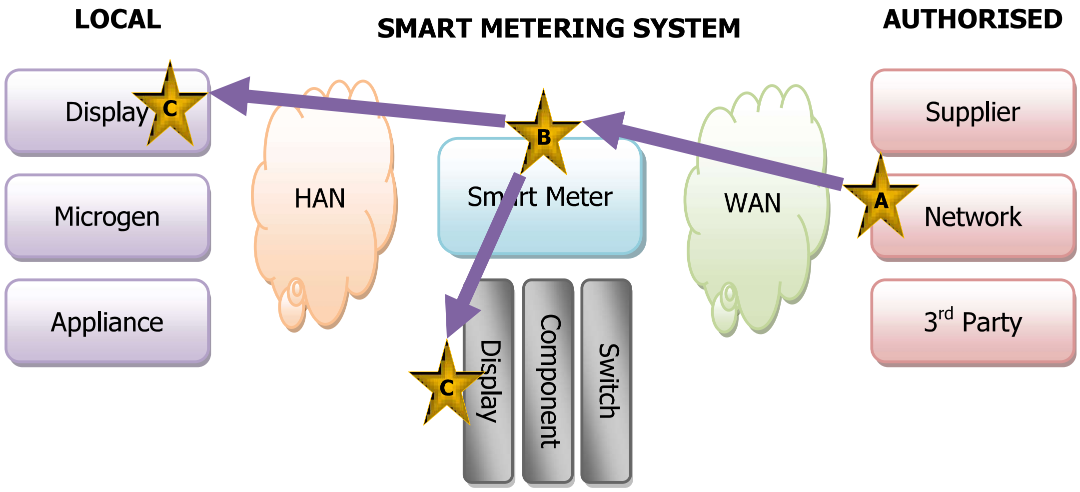
It is also useful to note that in this document it is assumed that any decisions regarding smart meter introduction in the UK will be the same for both ENA and ERA specifications.



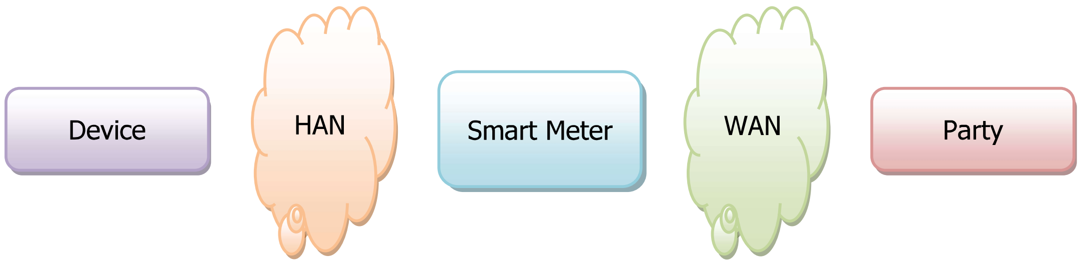
Requirements exist within both specifications to move data/messages between the rectangles through one or both of the communications clouds.

For example, requirement GDN 08.03 from the ENA specification requires the smart metering system to display notifications of planned gas outages to customers. This message would originate from the Network, be passed to the meter via the WAN, be displayed at the meter itself, and possibly also on the remote display via the HAN.

Shown below for this specific requirement, this is A to B to C. For other requirements, the message flow could be C to B to A, or B to A etc.



Distilling the figure above down to basic elements, a number of ERA and ENA requirements can be covered by this schema. Activities could originate within any rectangle (entity) and be passed to any other rectangle (entity) – having the functionality in the meter to accomplish one such activity results in a capability to support all such activities.



Once again, the SRSM specification includes requirements to undertake such messaging, therefore any ENA requirements for messaging are not seen as adding incremental costs. The A to B to C of any notification, alert or messaging is delivered by this architecture.

3.1.5 Additional Hardware

Accepting that a number of the different requirements in the ENA specification add minimal or no cost to the smart meter because they are functionally similar to ERA requirements or 'generic', the area where the ENA requirements does add potential cost is where extra hardware is required to meet requirements.

Mainly these requirements are asking a smart meter to detect or measure things which are not part of the Supplier requirements – e.g. voltage, power quality, temperature, etc.

The SRSM specification has very high level requirements for sensors, mainly to do with safety and tamper protection, and provides an example of the types of sensing and protection that might be required. The ERA, whilst developing the specification, discussed these details with the meter manufacturers who see this as an area for differentiation and product innovation. There is a note in the SRSM document recommending further detailed work in this area. Any development work should be cognisant of the need to keep the physical protections of smart meters as current as possible, possibly changing more frequently than other requirements, as the ingenuity of those who would seek to tamper with a smart meter will present new challenges regularly.

Therefore, where the ENA document places clear requirements that would require sensing or measuring requirements to support them, these are all seen as potentially incrementing the cost of a smart meter.

3.1.6 Increased Capability of Existing Hardware

A number of ENA requirements, whilst not adding to the number of components within a meter, will affect the size or capability of those components.

For instance, the SRSM specification includes a back-up battery for an electricity meter (B.ELE.004), but this is not required to maintain a WAN communications modem as DNO 05.03 could do – a larger battery or alternative solution may be required here – adding cost.

The three main scalable components within a gas or electricity smart metering system to be installed in a home are seen to be:

- Microprocessor – may need to be upgraded to be faster, or capable of multitasking, to cope with the additional monitoring and processing activities resulting from the ENA requirements;
- Memory - a number of requirements will result in the meter needing to hold more data. This might not necessarily result in a requirement for more memory (and therefore add cost), as it might just mean that memory buffers are refreshed more frequently; and
- Battery – as discussed above.

Meter memory is a fairly liquid resource and can be managed using any number of techniques. Suppliers could seek to reserve a proportion of meter memory for consumption data, with a separate portion for diagnostic data, and the remainder being available for other data. On the other hand, the whole data store could be operated as a single large volume with no partitions.

Usually memory to capture dynamic data items like consumption intervals and voltage profiles will operate on a First In First Out (FIFO) basis – the oldest data being overwritten by new data. Obviously, the more physical memory that is present, the less often that the FIFO processes will occur – a meter with 1MB of memory will overwrite data twice as quickly as one with 2MB of memory, provided they are both configured the same way.

The SRSM specification includes a requirement for a 'Low Memory Capacity Warning' (B.COM.046), but these could be very common messages if the meter is configured to collect a large amount of data to meet the ENA requirements. The obvious answer is to include more memory (and add more cost) to the meter.

At the same time, data does not have to be, and some would say should not be, stored at a very granular level within the meter – it should be collected and transmitted to an external data store. This could be within the In Home Display for consumption interval data (although, this option carries a risk of data being lost when the home display is changed, lost or damaged), or could be an enterprise application collecting power data from 27 million homes. Therefore increases in memory costs are likely to be small as it can be 'better managed'.

Microprocessors as might be used, in smart metering, are becoming increasingly sophisticated in their design and capability. Traditionally they are cheap, single core, generic chips that were called upon to measure energy or manage a basic proprietary operating system (e.g. for prepayment meters).

The introduction of smart metering presents new challenges for microprocessors in meters – with communications to a WAN and a HAN adding complexity, alongside monitoring consumption and other dynamic data in a much more granular fashion. Including diagnostic monitoring and consequential activities based upon dynamic data, the software needed to operate a smart meter is much more sophisticated, and consequently 'better' chips are needed.

This will become evident with activities within the meter 'compete' for microprocessor resources – chips with a lower specification may take longer to complete instructions or calculations and consequently other activities may be forced to wait until the microprocessor is 'free'.

As with other embedded microprocessors, technological advances provide much greater capabilities at relatively flat cost as time progresses, but at the moment there are market costs for levels of sophistication in the types of chips used in meters, and if there is a requirement for a meter to do more activities on more streams of data, there could be additional, marginal, cost in upgrading.

Overall, the increases in microprocessor costs are expected to be small because technology is continually improving.

Finally, for batteries, the cost differences are fairly simple. If a meter needed an AA battery to deliver one discrete set of requirements, and a C battery is needed when extra requirements are added, the cost differential is clear. Bigger batteries are generally more expensive (given that they are consistent in their quality/chemical make up). Considering that battery technology is likely to be static and the costs would increase with the requirements, ENA have tried to highlight where such requirements would cause additional cost by indicating some requirements as being optional (e.g. DNO 05.03) and estimating the costs of such requirements separately.

For each of these components – microprocessor, memory and battery - it should be possible to present further detail on the specific requirements, allowing meter manufacturers to determine the most appropriate component to deliver those requirements – i.e. a faster microprocessor, more memory or a bigger battery.

3.1.7 Additional ENA Requirements for Electricity

The analysis found 32 requirements to be unique to the ENA specification, and four optional requirements.

ENA Ref	Requirement	Notes	Requires Extra Meter Data Storage	Requires Extra Hardware
DNO 01.01	Meter to hold location information	Referenced in 2007 ERA SRSM Smart Metering Operational Framework (SMOF) as a possible data item to be held by meter. Remains simply a data item	Minimal – assumed none	
DNO 01.02	Upon installation, self register and issue a signal to the grid	Presupposes installation processes - is only one of a number of approaches to smart metering installation - requirement should be for smart meter installation data to support ENA business processes – adds no costs		
DNO 01.03	Configurable to automatically update the system to adapt to grid network system changes	Providing networks with information on new demand/generation connections		
DNO 02.02	Measure import/export reactive energy	Extra data to measure, store and communicate. There are no Supplier requirements to monitor reactive power – this is addressed by a specific variant in the SMOF	Yes	Yes
DNO 04.04	Record Half Hourly average RMS voltages	Extra data to measure, store and communicate	Yes (included in 04.11)	Measure Voltages
DNO 04.11	Meter will store voltage profile data for 3 months	Extra data to measure, store and communicate	Yes	
DNO 04.12	Meter will store a specified minimum number of Under and Over voltage events	Minimum not specified (for the purpose of this analysis it is assumed that the meter should be capable to store 100 most recent quality of supply events (which include: under/over voltage; loss of supply, voltage threshold setting, restore of supply, supply switch status))	Yes	
DNO 02.04	Capable of calculating and reporting power factors	Extra data to measure, store and communicate. May need bigger µ-processor, but assumed not for the purposes of this document – linkage to DNO 02.02	Yes	
DNO 04.06	Provide power quality information as configured and on demand	Is a generic communication requirement, but could add cost if detailed power quality information is required (assumed to include: power swell (as configured for threshold and duration); power sag (as configured for threshold	(already covered in other requirements)	

ENA Ref	Requirement	Notes	Requires Extra Meter Data Storage	Requires Extra Hardware
		and duration); average HH voltage; associated events including: power outage, power restoration, supply switch status; Under/Over voltage threshold setting; recorded emergency overrides)		
DNO 04.13	Store a configurable minimum number of power quality event recordings	Minimum not specified (assumed as per DNO 04.12)	Yes (included in DNO 04.12)	
DNO 04.15	Record power quality events			
DNO 06.02	Support basic load control functions	Looking to meter to automatically control load/devices within premises via HAN or by meter itself		
DNO 06.03	Support Emergency Override Control	Prioritised scheduling of load control events		
DNO 04.01	Detect under and over voltage levels	Covered by 04.06		
DNO 04.08	Issue an alarm when Over or Under Voltage is detected - configurable thresholds	An alert to a specified party upon the incidence of specific circumstances - Common requirement for both ERA and ENA, this specific requirement of more relevance to ENA		
DNO 04.03	Support remote energisation status check	Should be simple to measure		
DNO 05.01	Detect loss of supply	Should be simple to measure		
DNO 05.03	Issue alarm on detection of loss of supply. (Optional)	ENA requirement is very specific – Last gasp alert to be sent 3 to 5 minutes after loss of supply.		Yes – battery or capacitor (Optional)
DNO 05.05	Issue notification of when loss of supply restored	Diagnostic event		
DNO 05.02	Store loss of supply information for configured period	Store loss of supply information for configured period	Yes	
DNO 08.03	Will store loss of supply over 18 hours for at least 3 months	Store loss of supply information for configured period	Yes (included in 05.02)	
DNO 05.04	Communicate loss of supply duration information	Similar to DNO 05.05, but a different data set for the alert message		
DNO 02.11	In Built Temperature Sensor (optional)	Optional requirement difficult to assess		Yes (Optional)
DNO 04.02	Detect reverse polarity (optional	Optional requirement not possible without additional external		Yes (Optional)

ENA Ref	Requirement	Notes	Requires Extra Meter Data Storage	Requires Extra Hardware
	not considered)	hardware. Not considered here.		
DNO 04.10	Issue reverse polarity alarm	Is a diagnostic event/message - similar to those in SRSM, should attract no additional cost		
DNO 10.03	Be immune to magnetic fields from normal magnets, issue alert when stronger magnets are used	Requirement to comply with BS EN 50470 standard, adds no extra cost.		
DNO 04.07	Configurable parameters to support extreme under or over voltage detection	Simply configurable diagnostic thresholds		
DNO 04.14	Configurable to disable supply if extreme under or over voltage detected	Is an 'on event>take action' requirement, similar to zero balance for credit, or detecting cover removal.		
DNO 02.10	Support temperature sensing in an external device - i.e. connector block (optional)	Adds to physical components hence could add to overall cost of metering system in a home		Yes (Optional)
DNO 04.05	Configurable to provide average, min and max voltage on demand	Linked to other voltage measurement and storage requirements		
DNO 08.01	The meter shall be configurable to identify GSS (>18 hour) failures	Is a simple diagnostic event linked to loss of supply		
DNO 08.02	Configurable to detect and record GSS failures	Is linked to detecting loss of supply		

3.1.8 Requirements that Add Potential Cost (New Hardware)

This section summarises those items in the table above that could require new hardware in the meter and hence increase the cost of the electricity Smart Meter.

DNO 02.02 (and DNO 02.04) are seeking to measure reactive power – this is over and above the simple Supplier requirements for active energy measurement in all meters. Suppliers include a variant capable of measuring reactive power – anticipated to be a low volume of meters. It is clear that the Network companies have a requirement for reactive power capability in every meter. How the measurement of reactive energy is achieved via hardware and is a matter for meter design and manufacture, but it is understood that this will add a small cost to every meter.

DNO 04.04 (inter alia) is seeking to measure voltages. This will require hardware not included in the ERA SRSM specification as Suppliers have no interest in voltages. It is not anticipated that, for voltage, this will add material cost to the meter, as every other smart metering market in the world will be looking to monitor voltage and this will be part of any standard smart electricity meter.

DNO 04.06 (and others) are seeking to monitor/measure power quality. Given that this is restricted to voltage sag/swell incidents this should be relatively straightforward and add no cost. It becomes less straightforward where the sag results in the meter registering a loss of supply instead of a voltage sag. We have assumed there to be no requirement for an internal power source (battery or capacitor) to ensure processor continuity in cases when lower level sag recording is required – the loss of supply duration reporting is effectively the same as voltage sag duration reporting. We would anticipate the sag/swell monitoring requirements to include configurable thresholds.

DNO 04.02 is seeking to detect reverse polarity. We understand that this is not possible without additional hardware for single phase supplies, which represents the majority of domestic supplies in this country. Electricity meters in the UK are double insulated devices with no earth and therefore reverse polarity detection is not possible – it may be possible for some other device to detect this and provide information to the meter, but this would add hardware and cost. Therefore, this requirement is not further considered for cost and benefit analysis.

3.1.9 Requirements that Add Potential Cost (Extra Storage)

A number (5) of requirements will result in the meter needing to hold more data and process more information. As discussed above, memory is a fairly liquid resource and will operate on a First In First Out basis for dynamic items. However in order to stop memory capacity becoming a regular operational issue, including a larger maximum capacity within the meter at a relatively low cost could be seen as beneficial.

Within the ENA requirements document there are several requirements seeking to store voltage information, reactive power, and several looking to store Loss of Supply information for different Use Cases – these have been combined as indicated. In fact, from half hourly voltage profiles it should be possible to determine power quality and Loss of Supply events – potentially consolidating all of the data requirements into a single data 'store', but this consolidation would require further discussion of the requirements to ratify that the appropriate data would be collected.

Engage recommend that the requirements of Suppliers and Networks be modelled in detail to understand the typical and worst case impact scenarios on meter memory, but would not anticipate the additional data requirements as expressed in the ENA requirements to add much cost to the overall cost of a meter. This analysis should take account of sophisticated memory management options, and alternative 'off meter' solutions as discussed above. It should also be careful to avoid potential double-counting when estimating the 'worst case' requirements for memory.

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Memory is relatively inexpensive and exponential increases in capacity do not come with similar cost increase, therefore we'd anticipate the additional cost of the ENA requirements to be less than a pound per meter.

The requirements seen as potentially adding memory are: DNO 02.02, 02.04, 04.11 (includes 04.04), 04.12 (04.13), 05.02 (08.03).

3.1.10 General Notes

DNO 01.01 whilst considered in the ERA SMOF requirements (not the Metering System Requirements) as a useful data item to store, this is not a specific ERA requirement. Whilst the ERA SRSM has published an updated view of meter functionality, it has not updated the data models published in the 2007 SMOF. This ENA requirement could add cost to the overall smart metering solution as it could require location sensing equipment, carried by the installer, to be used at installation, but the cost of storing 1 additional data item within the metering system is not material.

DNO 03.01 is largely consistent with the ERA requirements for flexible tariff arrangements, but lists dynamic pricing as an example of a possible approach. This is not covered by the ERA specification and could require significant further discussion to determine pricing and communication requirements – e.g. is this real time pricing? How long are prices applicable? Are there any specific thresholds? What interaction is expected of the customer?

DNO 06.02 is looking for meters to be able to automatically control load to prevent issues occurring on the network. This might be as simple as offsets for switching of loads to avoid peaks, or it might be direct automatic control of devices on the HAN. This is an area that is not addressed specifically in SRSM. It is not anticipated to add material cost to the meter as this can be achieved within software and via the HAN, but it would warrant further detailed discussions to appreciate the potential ramifications of the requirement. The main cost is likely to be in the appliances beyond the smart meter – these would need compatible HAN hardware to be part of a switchable load.

DNO 10.02 is about protecting the meter and communications from magnetic fields. Hence, all the smart meters should ensure compliance with BS EN 50470, which should add no extra cost as this is a basic requirement.

3.1.11 Optional Requirements

DNO 02.10 discusses detecting external temperature to determine possible supply issues. The requirement appears to be an illustration of an alternative solution to a different temperature sensing requirement. If this is to be incorporated in every meter it would appear to require additional interface hardware in every meter and this would be likely to add costs. The alternative discussed in 02.11 (in built temperature sensor) is also optional, which makes it difficult to assess as part of an overall cost assessment.

DNO 05.03 is seeking for the meters to be capable of detecting a loss of supply, waiting for 3 to 5 minutes to ensure that the loss of supply has continued and then to send an alert about the loss of supply. It is not specific on how an electricity meter without power would accomplish this. The assumption is that a backup battery or capacitor is used to meet this requirement. It is understood that, depending on the WAN communications solution, the hardware requirements (and cost) would vary, and could vary significantly.

DNO 04.02 (issue reverse polarity alarm) is not considered in this analysis as is not possible to implement within GB meters without additional external hardware which would result in high costs.

3.1.12 Cost of Latent Functionality

In the ENA specification, a number of requirements are noted as not being required to be used regularly for every meter, but that having access to latent functionality within every meter is important. Whilst this is possible for generic requirements, such latent functionality that places additional hardware/cost in every meter would need to be examined carefully from a cost/benefit perspective – this would relate to the measurement of reactive power, voltage sags and swells, power quality etc.

3.1.13 Additional ENA Requirements for Gas

The analysis found 5 requirements to be unique to the ENA specification, one being an optional requirement.

ENA Ref	Description	Notes
GDN 02.05	Configure to use CV from specific start date and time	Similar to tariffs and other items - can be scheduled for application from a point in the future
GDN 02.07	Measure and Store calorific values within meter (optional)	Optional requirement, subject to cost. Possibly warrants further detailed discussion to understand the possibilities and implications
GDN 05.05	Positive response from meter where a valve closure has been requested	Difficult to prove that a meter can guarantee the valve has actually closed as requested
GDN 08.01	Visual display of time remaining before automatic valve operation of open or close	Different 'type' of requirement from SRSM ones, but should be possible utilising the specified hardware
GDN 08.02	Display status of valve	Similar to a number of SRSM requirements to display status or mode of operation etc.

None of these 'ENA only' requirements would add cost to the SRSM base gas smart meter, as they are all utilising existing hardware or functionality.

GDN 05.05 places a requirement on the meter to provide a positive response on a valve closure. This may be difficult for software to prove absolutely, and the SRSM specification includes a requirement about not opening a valve when flow is detected, but nothing to detect flow when a valve is supposed to be closed.

This type of requirement is probably best addressed by reference to an appropriate standard for gas tightness within the valve. Engage Consulting are aware of the ongoing discussions within the CEN group looking at gas smart metering and would recommend that any specification for smart meters with valves refer to the relevant draft/final European technical standard for gas tightness.

It is not viewed that the ENA requirement for this type of positive response on valve closure adds cost to the meter.

The optional requirement GDN 02.07 looks for meters to measure and manage their own individual thermal gas calculations – i.e. measure calorific value within the meter. This could have a significant impact on the overall cost of deployment, as we understand it is not possible for a diaphragm meter to meet this requirement, and therefore every smart gas meter would have to be an ultrasonic meter.

Noted that GDN 02.02 relates to a very specific solution for the Central Communications Provider. However, the requirement is essentially for a gas meter to provide readings according to a schedule, which is very clearly also an ERA requirement. There appears to be no specific Gas Network requirement to obtain readings from a central source, rather than reads are uploaded on a schedule to a central source.

3.1.14 ENA Communications Requirements

Analysis of the 9 ENA requirements for communications shows a largely consistent approach to the ERA SRSM documentation. Only COM 02.03 is inconsistent, and then only for the use of specific terminology. The ERA specification discusses only WAN and Local Communications (HAN), but not a LAN, as this would presuppose a communications infrastructure solution that included a LAN.

This is not a material difference, and the specific requirements referencing LAN do not introduce new costs.

3.1.15 Further Work

Within the specifications, both documents include a number of assumptions, example data sets, notes and place holders for further discussion to resolve the detail. Some of this is dependent on further clarity in the overall architecture of the smart metering infrastructure, or other policy areas, but a great deal of it could be addressed relatively quickly by an appropriate industry working group.

To illustrate the potential level of work, the table below highlights the requirements noted from both documents where further discussion or analysis is required. A number of these may be listed as ERA or ENA only, but are likely to be of interest to a joint working group.

Ref	Requirement	Actions/Note	Applies to
B.ELE.001	Suitable for installation locations	Requirement for accuracy class to be resolved	ERA
B.ELE.003	Standards conformance for terminals	Full normative reference required	ERA
B.ELE.004	Include a battery in electricity meter for essential functionality	This functionality needs to be defined	ERA (joint)
B.ELE.005	Include a switch/contactor	More work required on how switch operates in	ERA (joint)

Ref	Requirement	Actions/Note	Applies to
		FITs/Microgen/Prepay scenarios	
B.ELE.007	Barcode	Symbology standard for barcode to be agreed	ERA
B.ELE.009	Energy consumption compliant with licence	Licence conditions may need to be revised in light of national mandate for smart metering	ERA (joint)
B.ELE.010	Standards compliance for Energy Consumption	Note against requirement, but whole topic of powering electricity meters and communications boxes needs to be resolved	ERA
B.GAS.001	Standards compliance for pipework and fixings	Correct standards need to be quoted	ERA
B.GAS.009	Prevent valve opening if flow detected	May need to be rewritten following draft of EU smart meter standards	ERA
B.GAS.011	Prioritisation of functionality during battery failure	To be agreed	ERA (joint)
B.GAS.012	Barcode	Symbology standard for barcode to be agreed	ERA
B.COM.002	Possible requirements/buttons for a minimum agreed human interface	To be discussed and agreed	ERA
B.GAS.014	Use of calorific values to calculate kWh	Business process/calculations to be discussed	ERA (joint)
B.COM.007	Operate as a multirate meter	Currently no upper limit on number of possible registers in a tariff – need to agree a number	ERA
B.COM.023	Display a mandatory minimum data set to customer	Minimum data set to be agreed	ERA (joint)
B.COM.024	Store a mandatory data set in persistent memory	Data set to be agreed	ERA (joint)
B.COM.026	Sufficient memory overhead to support all requirements	Needs to be determined once all requirements are clear	ERA (joint)
B.COM.030	Record diagnostic information	Further definition/requirements needed	ERA (joint)
B.ELE.019	Customer to positively acknowledge re-enable after remote disable	Part of Human Interface requirements	ERA
B.ELE.020	Customer to positively acknowledge re-enable after credit disable	Part of Human Interface requirements	ERA
B.GAS.019	Customer to positively acknowledge re-enable after remote disable	Part of Human Interface requirements	ERA
B.GAS.020	Customer to positively acknowledge re-enable after credit disable	Part of Human Interface requirements	ERA
B.COM.052	Clock can be synchronized	Resolve preference for how this is done	ERA (joint)
B.COM.055	Replicate display characteristics of current prepay metering	Needs to be agreed	ERA
B.COM.057	Local manual credit updates	Business process to be discussed	ERA
B.COM.063	Configurable non-disable periods	Balance recovery following non-disable period to be resolved	ERA
DNO 04,01	Measure Voltage	To be defined in detail later	ENA

Ref	Requirement	Actions/Note	Applies to
DNO 04.03	Remote energisation status check	To be defined in detail later	ENA
DNO 05.03	Loss of Supply alarm	To be defined in detail later	ENA
DNO 04.05	Average Voltages	To be defined in detail later	ENA
GDN 02.06	Store gas consumption data	To be defined in detail later	ENA
GDN 05.05	Acknowledge positive valve closure	To be defined in detail later	ENA

For a large number of ENA requirements, a 'typical' information set expected is defined, with a 'such as' definition. It is assumed that each of these data sets, usually within the criterion element of a requirement, would require some further discussion, but we should take the assumptions as is at this point.

There are also a number of ENA requirements requiring that the meters retain a minimum data set for a minimum of 3 months, but without defining the minimum data set. These data sets will need to be defined to ensure that we can scope the potential memory capacity necessary within a meter to deliver the requirements. (DNO 04.13, DNO 02.06, DNO 04.12, DNO 05.02, DNO 08.03).

For DNO 02.02 and DNO 02.04 there may be a requirement for further discussion of the direction (lead/lag) of half hourly average power factors, how they are captured and the data needed to support these requirements.

3.2 Extra Network Smart Metering Requirement Cost Implications Using BEAMA Cost Estimations

This section assesses the ENA smart metering requirements that add extra cost as was identified within the Comparison of ERA SRSM and ENA Smart Meter Requirements Document using cost implications as identified by BEAMA. The rest of the specifications not mentioned in this document are considered as being common to the networks, suppliers and DECC thus not adding extra costs to the smart meter. Where assumptions have been made as part of this work, they are clearly highlighted within the document.

3.2.1 Costs Assessment

Engage has produced an analysis of the smart metering requirements from SRSM project and ENA project and identified the ENA requirements that could add additional cost to the meter on top of the ERA and DECC requirements.

In total 2 requirements were identified that could add hardware to the meter specification, and 4 requirements that result in additional cost due to increased data storage requirement.

The table below summarises the requirements that have been recognised as adding extra costs on top of DECC and SRSM requirements.

Table 1 – Network Electricity Requirements adding extra costs to the smart meter

ENA Ref	Requirement	Analysis Notes	Requires Extra Meter Data Storage	Requires Extra Hardware	BEAMA estimated cost	BEAMA notes
DNO 01.01	Meter to hold location information	Referenced in 2007 SMOF as a possible data item to be held by meter. Remains simply a data item.	Minimal – assumed none			Possible with some configuration hardware and software. Would need detail on what and how the information would be stored but should not have an impact on hardware cost unless requirements are onerous.
DNO 02.02	Measure import/export reactive energy	Extra data to measure, store and communicate	Yes	Yes[1]	£0-£0.50	May need extra testing
DNO 02.04	Capable of calculating and reporting power factors	Extra data to measure, store and communicate	Yes		Negligible and included in 02.02	Dependant on other functionalities and type of power measurement technology. This might also need more powerful microprocessor
DNO 04.02 (optional)	Detect reverse polarity			Yes	No meter cost	It is not possible to detect the reverse polarity within the meter in the UK as it requires an earth connection;

[1] BEAMA view that measuring reactive power would result in additional hardware costs – covered by 02.04

ENA Ref	Requirement	Analysis Notes	Requires Extra Meter Data Storage	Requires Extra Hardware	BEAMA estimated cost	BEAMA notes
						therefore this would require additional devices outside the meter and it thus would have significant cost implications.
DNO 04.04	Record Half Hourly average RMS voltages	Extra data to measure, store and communicate	Yes	Measure Voltages	Negligible	
DNO 04.06	Monitor / measure power quality	The information assumed to include: power swell (as configured for threshold and duration); power sag (as configured for threshold and duration); average HH voltage; associated events including: power outage, power restoration, supply switch status; Under/Over voltage threshold setting; recorded emergency overrides. Assume no requirement for an internal power source (battery or capacitor) to ensure processor continuity in cases when lower level sag recording is required.	(already covered in other requirements)	No		The cost might increase significantly depending on Power Quality measuring requirements. The requirement is to record and notify an event of sag and swell (e.g. at a predetermined voltage, say 10% or 20% of RMS). This can be accommodated within other data requirements since the event would just be an extra piece of data passed to memory. If a battery within the meter was introduced as a requirement, duration of the dip could also be given since the battery

ENA Ref	Requirement	Analysis Notes	Requires Extra Meter Data Storage	Requires Extra Hardware	BEAMA estimated cost	BEAMA notes
						within the meter would keep the clock functioning.
DNO 04.11	Meter will store voltage profile data for 3 months	Extra data to measure, store and communicate	Yes		£0.30	
DNO 04.12	Meter will store a specified minimum number of Under and Over voltage events	Minimum not specified (for the purpose of this analysis it is assumed that the meter should be capable to store 100 most recent quality of supply events (which include: under/over voltage; loss of supply, voltage threshold setting, restore of supply, supply switch status, tariff setting)	Yes		-	Should not impact cost unless memory storage requirement become onerous
DNO 04.13	Store a configurable minimum number of power quality event recordings	Minimum not specified (as mentioned in 04.12)	Yes			
DNO 04.15	Record power quality events					
DNO 05.02	Store loss of supply information for configured period	Store loss of supply information for configured period	Yes		£0.30	Possible but will have impact on memory if outages expected are frequent.
DNO 05.03 (optional)	Issue alarm on detection of loss of supply.	ENA requirement is very specific - alert to be sent 3 to 5 minutes after loss of supply. It is understood that, depending		Yes – battery or capacitor	£1-£5[2]	Last gasp comms can be quite expensive for most comms technology. Concern that

[2] According to BEAMA, the cost depends on the assumptions made by the meter manufacturers.

ENA Ref	Requirement	Analysis Notes	Requires Extra Meter Data Storage	Requires Extra Hardware	BEAMA estimated cost	BEAMA notes
		on the WAN communications solution, the hardware requirements (and cost) would vary, and could vary significantly.				all meters in an area would be sending alarm simultaneously and possibly overload comms system
DNO 08.03	Will store loss of supply over 18 hours for at least 3 months	Store loss of supply information for configured period	Yes (included in 05.02)		-	Central Data
DNO 02.11 (optional)	In Built Temperature Sensor	Optional requirements are difficult to assess		Optional	£0.50 - £2.00	Possible that thermal sensor connected direct to I/O so contactor would be opened in extreme heating conditions. For true temperature measurement cost would be the higher of the figures given.
DNO 02.10 (optional)	Support temperature sensing in an external device - i.e. connector block	Adds to physical components = could add cost		Optional	£0.50 - £2.00	

The table below provides a summary of costs for hardware, storage and optional requirements.

Cost split	Requirements	Cost per requirement	Total
Extra Hardware cost	DNO 02.02 DNO 04.04 DNO 04.06	Inc in DN0 02.04 Negligible 0[3]	Negligible
Extra Memory Storage cost	DNO 02.02	£0 - £0.50	c.£0.60 - £1.10
	DNO 02.04	Negligible	
	DNO 04.11	£0.30	
	DNO 04.12	0	
	DNO 05.02	£0.30	
Optional Requirements cost	DNO 05.03	£1-£5	c. £1.50 - £7.00
	DNO 02.10 DNO 02.11	£0.50 - £2.00	

None of the 'ENA only' gas requirements are considered to add extra costs to the meter. However, this is on the basis that the optional element of requirement GDN 02.07 is not included (looking for meters to measure and manage their own individual thermal gas calculations – i.e. measure calorific value within the meter). This could have a significant impact on the overall cost, as we understand it is not possible for a diaphragm meter to meet this requirement, and therefore every smart gas meter would have to be an ultrasonic meter. This cost implication analysis excludes this optional element of requirement GDN 02.07 for this analysis.

The functionality not mentioned here is assumed to be common to the networks, suppliers and DECC, thus is not incremental.

It is also assumed that a separate communication box will be used with the smart meters and this would be common to all the related parties. Such box is estimated to add £15 WAN capability and is expected to fall within Government cost therefore it is not included as part of the incremental costs in this analysis.

3.3 Data Traffic Volume Impact

This section identifies which elements of the data traffic analysis (ENA-CR008-001-1.4) are common to Network Operators and Suppliers. This provides input to Ofgem to identify the incremental data traffic for network requirements alone and therefore model true incremental costs. The incremental traffic will not be costed within this paper, since it is dependent on the communication infrastructure deployed and assumptions made in any cost model.

3.3.1 Common ERA/ENA Data Traffic Assessment

An optimised industry model could allow some "central" data storage and access to that central storage by appropriate parties and as a consequence reducing the individual traffic between parties and meters. If such an architecture were adopted the common data traffic could then be netted from the results of the previous data traffic analysis to show the true increment for Network Operator

[3] Covered by 04.04 costs

requirements. This assessment explores examples of the potential for the overall industry data traffic to be optimised. Please note that no data traffic is known with any certainty: the ENA Data Traffic Analysis document is a work in progress and might be updated at a later stage. However this work, and its associated assumptions, has been used to create a baseline for this analysis. It is not possible at this stage to compare the estimated ENA traffic with any comparative supplier or market-wide data, as that data is not in the public domain.

This evaluation has used the assessment of the Data Traffic (ENA-CR008-001-1.4) required to support the ENA Use Cases (ENA-CR007-02-1.1) and identified the activities that involve data that is regarded as ENA specific and those that are thought to have data of value to both Network Operators and Suppliers. Identification of such data could be useful for future smart metering data management optimisation processes and provide a potential reduction of costs associated with the required data storage requirements and communication network capacity requirements by storing some common data centrally and allowing Network Operators and Suppliers' common access.

However, the timing of potentially common Network Operators and Suppliers activities may not coincide and the ability to minimise the data traffic in these areas by 100% is likely to be limited. The maximum overlap would only occur if all "common data" were collected and Network Operators or Suppliers could access this common data from a central data management agency (e.g. Data and Communication Company – DCC). Due to this uncertainty it has been decided to consider three scenarios to represent the potential overlap.

- Scenario 1 – 90% of the ENA/ERA overlapping data is optimised to be used by both parties instead of creating separate transmissions of the same data;
- Scenario 2 – 50% of the ENA/ERA overlapping data is optimised; and
- Scenario 3 – 10% of the ENA/ERA overlapping data is optimised.

3.3.1.1 Common Electricity Data

The analysis showed that the following electricity data could potentially be used by the Network Operators and Suppliers:

Table 1 – Potential Electricity related Data used by Suppliers and Network Operators

Type of data		Message size per transmission	Sum per transmission	Volume per year	Sum per year
Assessment of network performance (planning)		(bytes)	(bytes)	(bytes)	(bytes)
Use Case 01 - Monitor current flows and voltage levels to identify thermal capacity and statutory voltage headroom					
1. Data is periodically sent from the Smart Metering System	Real Power (import) (kW)	18236		72944	
	Real Power (export) (kW)	18236		72944	
	Micro-generation Real Power (kW)	18236	**54,708**	72944	**218,832**
Actively manage network / System Balancing					
09 Use Case - Perform Active Management of Network Power Flow					
4. Direct Control, by DNOs, of appliance or micro-generation	Command to control (disconnect) the appliance or disable supply	597		2388	
	Command to reconnect the appliance or enable the supply	597	**1194**	2388	**4776**
Actively manage network during planned and					

unplanned Outage					
Use Case 17 - Restore and maintain supply during outages					
2. DNO activates the maximum power consumption threshold	Command to activate power threshold	597	**597**	1194	**1194**
Support network activities					
Use Case 20 - Configure Smart Metering System					
1. DNO configures meter reading registers	DNO configures meter reading register	597	**597**	597	**597**
2. DNO configures meter alarms	DNO configures meter alarms	597	**597**	597	**597**
3. DNO configures meter load threshold	DNO configures load threshold	597	**597**	597	**597**
Total			**57,693**		**225,399**

Table 1 above also gives an overview of the size of this data transmission in bytes. It should be noted that over 90% of potential common data constitutes data that network companies would use for planning (energy consumption reads saved within the meter for 3 months).

Table 2 and 3 below provide an overview of the ERA/ENA common data volume and how much data reduction could be achieved under different scenarios. Table 2 is based on the planning data transmission every 3 months, whereas Table 3 provides the volume of common ENA/ERA data per year.

As highlighted above, if suppliers move towards the use of more granular data to meet their own requirements, then the overlap of data increases. There may be geographic areas or customer groups that require this additional element of granular data.

Table 2 – Potential Electricity data overlaps between ERA and ENA per transmission in bytes

	Total ENA data flow per electricity meter [4]	Potential common ENA/ERA data	Scenario 1 - Data volume saving: 90% of common data	Scenario 2 - Data volume saving: 50% of common data	Scenario 3 - Data volume saving: 10% of common data
	(bytes)	(bytes)	90%	50%	10%
Meter works well	332,980	57,693	51,924	28,847	5,769
Meter fails once	419,342	-	-	-	-
27 million electricity meters (TB)	**8.2**	**1.4**	**1.3**	**0.7**	**0.1**

Table 3 – Potential Electricity data overlaps between ERA and ENA per annum in bytes

	Total ENA data flow per electricity meter per year (planning data transmitted every 3 months)	Potential common ENA/ERA data	Scenario 1 - Data volume saving: 90% of common data	Scenario 2 - Data volume saving: 50% of common data	Scenario 3 - Data volume saving: 10% of common data
	(bytes)	(bytes)	90%	50%	10%
Meter works well	1,287,624	225,399	202,859	112,700	22,540
Meter fails once	1,375,180	-	-	-	-
27 million electricity meters (TB)	c.30-40	5.5	5	2.8	0.55

[4] Based on the assumption of planning data transmission every 3 months

Taking into account that over 90% of the common data volume falls under the planning data activity that potentially could be shared by both parties, then there is a high possibility for data optimisation.

3.3.1.2 Common Gas Data

With regards to gas, the analysis showed that the following gas data could potentially be used by the Network Operators and the Suppliers:

Table 4 – Potential Gas related Data used by ERA and ENA

Type of data		**Message size per transmission**	**Sum per transmission**	**Volume per year**	**Sum per year**
Use Case 1 - Gather information for planning		(bytes)	(bytes)	(bytes)	(bytes)
1. The Smart Metering System sends the recorded gas demand data to the GDNO (30min)	Interval Gas values	35612	**35612**	71224	**71224**
The Smart Metering System sends the recorded gas demand data to the GDNO (daily)	Daily Gas values	1302	**1302**	2604	**2604**
Use Case 02 - Configure Smart Metering System					
1. GDN configures meter reading registers	GDN configure meter reading register	597		597	
	GDN configure meter alarms	597	**1194**	597	**1194**
Use Case 03 – Disable Supply of Gas					
1. Gas is disabled by GDNs	GDN disables gas supply	597		597	
	GDN enable gas supply	597	**1194**	597	**1194**
Tampering Notification send to GDNs					
Meter sends tampering notification to GDNs	Meter sends tampering notification	597	**597**	597	**597**
Total			**39,899**		**76,813**

As with the electricity data it can be noticed from Table 4 above that over 90% of the common data volumes consist of the planning data (Use Case 1), this however can be quite different in reality as the original requirements of the Network Operators is to receive 6 min intervals from a sample meters, whereas suppliers are likely to want data from the meters they are responsible for but with measurements at much less frequent intervals. From the current requirement assumptions it is difficult to see the same level of data with common overlap as for Electricity.

The rest of the activities such as configuration of the smart metering system and disablement of gas would need to be performed to meet different needs of the Network Operators and the Suppliers again presenting little chance of sharing these data transmissions although the results of a disablement request may be of interest to multiple parties.

Table 5 and 6 below provide an overview of the ERA/ENA gas related potential common data volume and potential reductions under the different scenarios. Table 5 is based on the planning data transmission every 6 months, whereas Table 6 provides volumes of the gas data per year.

Table 5 – Potential Gas data overlaps between ERA and ENA per transmission in bytes

	Total ENA data flow per gas meter [5]	Potential common ENA/ERA data	Scenario 1 - Data volume saving: 90% of common data	Scenario 2 - Data volume saving: 50% of common data	Scenario 3 - Data volume saving: 10% of common data
	(bytes)	(bytes)	90%	50%	10%
Meter works well	361,170	39,899	35,909	19,950	3,990
Meter fails once	382,620	-	-	-	-
20 mil gas meters (TB)	**6.6**	**0.7**	**0.65**	**0.4**	**0.07**

Table 6 – Potential Gas data overlaps between ERA and ENA per annum in bytes

	Total ENA data flow per gas meter per year (planning data transmitted every 6 months)	Potential common ENA/ERA data	Scenario 1 - Data volume saving: 90% of common data	Scenario 2 - Data volume saving: 50% of common data	Scenario 3 - Data volume saving: 10% of common data
	(bytes)	(bytes)	90%	50%	10%
Meter works well	803,847	76,813	69,132	38,407	7,681
Meter fails once	825,297	-	-	-	-
20 mil gas meters (TB)	c.15-20	1.4	1.3	0.7	0.14

Considering various objectives behind the activities of the Network Operators and Suppliers, there would be little opportunity to combine such actions as meter configuration and disablement/enablement of gas supply due to the difference in the required time period to perform such activities by Network Operators and Suppliers. Additionally, although over 90% of the common data volume falls under the planning data activity that potentially could be shared by both parties, because of the differences in requested read intervals (ENA – 6 min/ ERA – 30 min) and the limitation of this requirement to only a specified number of meters which could differ further between the Network Operators and Suppliers. Based on this there is less chance for this data to be shared between Network Operators and Suppliers.

3.3.1.3 Consolidated Results

Overall, in the original ENA data traffic analysis document the total volume of data prior to data transmission between the smart meter and the other party (which was assumed to occur every 3 months for electricity) reached around 325 Kbytes6 per electricity meter, of which the common ENA/ERA data amounts to around 56 Kbytes. It is important to note that over 90% of overlapping data requirements consists of planning timescale data, i.e. import/export power reads, and micro-generation power reads.

For gas, the data traffic analysis estimated a total of around c.355 Kbytes of data per meter prior to data transmission (which for gas is assumed to occur every 6 months), of which the common ENA/ERA data amounts to around 38 Kbytes. As

[5] Based on the data transmission every 6 months. These figures reflect 30 minute interval gas data which is in line with Supplier requirements. ENA analysis assumed requirement for 6 minute data.

[66] 325 Kbytes obtained by dividing 332,980 bytes by 1024 to transfer bytes into kilobytes using the binary system. This also applies to other transfers from bytes into kilobytes and terabytes: 1Kbyte = 2^{10} and 1Tbyte = 2^{40} bytes.

with electricity, over 90% of the overlapping data requirements consists of planning data, which in this case includes gas interval reads.

Considering data transferred per year, the total data volume per electricity meter per year was estimated to be around 1,260 Kbytes, of which the common data volume amounts to 220 Kbytes per meter per year.

For gas, the total data volume per year reaches around 785 Kbytes, of which the common data volume amounts to around 75 Kbytes per gas meter per year.

The table below summarises the results of the analysis per each meter:

	Total (per quarterly transmission)	Common ENA/ERA data requirements (per quarterly transmission)	Total (per year)	Common ENA/ERA data requirements (per year)
Electricity meter	325 Kbytes	56 Kbytes	c.1,260 Kbytes	220 Kbytes
Gas meter	355 Kbytes	38 Kbytes	785 Kbytes	75 Kbytes

When considering common data volumes for total electricity and gas meter populations in the UK, 27 million electricity meters are estimated to create around 8.2 TB of data per data transmission, of which common data is estimated to reach around 1.4 TB.

Per year, the total data volumes for 27 million electricity meters would reach between 30-40 TB of which common data represents 5.5 TB.

For 20 million gas meters the total data volumes were estimated at around 6.6 TB per transmission, of which the data of common interest is 0.7 TB per data transmission.

Per year the total ENA gas related data is estimated to reach 15-20 TB, of which commonly requested data would be 1.4 TB.

The table below summarises the data for total UK meter population:

	Total (per quarterly transmission)	Common ENA/ERA data requirements (per quarterly transmission)	Total (per year)	Common ENA/ERA data requirements (per year)
27 mil Electricity meters	c.8.2 TB	1.42 TB	30-40 TB	5.5 TB
20 mil Gas meters	6.6 TB	0.7 TB	15-20 TB	1.4 TB

3.4 Potential Scale of Change to Network Operator Systems & Processes

This section identifies the scale of changes to existing DNO systems that are required in order to manage the increase in data delivered as part of the smart metering solution. The potential scale of developments to DNO systems and processes necessary to accommodate smart metering data have been identified at a very high level, and not quantified at this stage. The firm requirements of any such developments will be dependent on the smart metering market design (e.g. the scope of any central communications service). The Low Carbon Network Fund trials provide an opportunity to identify the scale of any necessary changes once the smart metering market design is known.

The costs associated with implementing these changes have not been included in the cost benefit analysis and once the dependencies above become firm policy, further work can be undertaken to quantify any impact on DNO systems.

ENA Ref	Requirement	Analysis Notes	Scale of Change to DNO Network, Systems and Processes
DNO 01.01	Meter to hold location information	Referenced in 2007 ERA SRSM Smart Metering Operational Framework (SMOF) as a possible data item to be held by meter. Remains simply a data item	None - All data in meter
DNO 01.02	Upon installation, self register and issue a signal to the grid	Presupposes installation processes - is only one of a number of approaches to smart metering installation - requirement should be for smart meter installation data to support ENA business processes – adds no costs	Amendments to outage management, mapping (GIS) and customer related databases.
DNO 01.03	Configurable to automatically update the system to adapt to grid network system changes	Providing networks with information on new demand/generation connections	Development of LV network control system, amendments to HV and EHV network control systems and customer databases
DNO 02.02	Measure import/export reactive energy	Extra data to measure, store and communicate. There are no Supplier requirements to monitor reactive power – this is addressed by a specific variant in the SMOF	Systems to be established to receive information stream / interrogate meters and store data. Network analysis package to be developed, populated and run to utilise the information.
DNO 04.04	Record Half Hourly average RMS voltages	Extra data to measure, store and communicate	Systems to be established to receive information / interrogate meters and store data. Network analysis package to be developed, populated and run to utilise the information.
DNO 04.11	Meter will store voltage profile data	Extra data to measure, store and communicate	Included in DNO 04.04

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ENA Ref	Requirement	Analysis Notes	Scale of Change to DNO Network, Systems and Processes
	for 3 months		
DNO 04.12	Meter will store a specified minimum number of Under and Over voltage events	Minimum not specified (for the purpose of this analysis it is assumed that the meter should be capable to store 100 most recent quality of supply events (which include: under/over voltage; loss of supply, voltage threshold setting, restore of supply, supply switch status, tariff setting))	Included in DNO 04.04, but with additional functionality to establish and implement configurable thresholds.
DNO 02.04	Capable of calculating and reporting power factors	Extra data to measure, store and communicate. May need bigger μ-processor, but assumed not for the purposes of this document – linkage to DNO 02.02	Included in DNO 02.02
DNO 04.06	Provide power quality information as configured and on demand	Is a generic communication requirement, but could add cost if detailed power quality information is required (assumed to include: power swell (as configured for threshold and duration); power sag (as configured for threshold and duration); average HH voltage; associated events including: power outage, power restoration, supply switch status; Under/Over voltage threshold setting; recorded emergency overrides)	Included in DNO 04.12, but with additional functionality to feed alarms into outage management and (LV and HV) control systems.
DNO 04.13	Store a configurable minimum number of power quality event recordings	Minimum not specified (assumed as per DNO 04.12)	Included in DNO 04.04
DNO 04.15	Record power quality events		Included in DNO 04.04,
DNO 06.02	Support basic load control functions	Looking to meter to automatically control load/devices within premises via HAN or by meter itself	Development of LV network control system, amendments to HV and EHV network control system to implement demand response and obtain confirmatory feedback. Amendments to outage management, mapping (GIS) and customer related databases. Demand response systems to be established
DNO	Support	Prioritised scheduling of load control	Included in DNO 06.02

ENA Ref	Requirement	Analysis Notes	Scale of Change to DNO Network, Systems and Processes
06.03	Emergency Override Control	events	
DNO 04.01	Detect under and over voltage levels	Covered by 04.06	Included in DNO 04.12
DNO 04.08	Issue an alarm when Over or Under Voltage is detected - configurable thresholds	An alert to a specified party upon the incidence of specific circumstances - Common requirement for both ERA and ENA, this specific requirement of more relevance to ENA	Included in DNO 04.12 with the additional functionality to initiate an alarm.
DNO 04.03	Support remote energisation status check	Should be simple to measure	Amendments to outage management, mapping (GIS) and customer related databases.
DNO 05.01	Detect loss of supply	Should be simple to measure	None - All functionality in meter
DNO 05.03 (optional)	Issue alarm on detection of loss of supply.	ENA requirement is very specific - alert to be sent 3 to 5 minutes after loss of supply. It is understood that, depending on the WAN communications solution, the hardware requirements (and cost) would vary, and could vary significantly.	Amendments to outage management, LV network control systems, mapping (GIS) and customer related databases.
DNO 05.05	Issue notification of when loss of supply restored	Diagnostic event	Amendments to outage management, control systems, mapping (GIS) and customer related databases.
DNO 05.02	Store loss of supply information for configured period	Store loss of supply information for configured period	Included in DNO 05.05 with the additional function to configure periods
DNO 08.03	Will store loss of supply over 18 hours for at least 3 months	Store loss of supply information for configured period	Included in DNO 05.02
DNO 05.04	Communicate loss of supply duration information	Similar to DNO 05.05, but a different data set for the alert message	Included in DNO 05.05 with the additional function to provide and issue customer information. Systems to do this to be developed.
DNO 02.11 (optional)	In Built Temperature Sensor	Optional requirements are difficult to assess	Amendments mapping (GIS) and customer related databases with the ability for receiving alarms.
DNO 04.02	Detect reverse polarity	Optional requirement not possible without additional external	Initial functionality all in meter

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ENA Ref	Requirement	Analysis Notes	Scale of Change to DNO Network, Systems and Processes
(Optional)		hardware. Not considered here.	
DNO 04.10	Issue reverse polarity alarm	Is a diagnostic event/message - similar to those in SRSM, should attract no additional cost	Included in 02.11
DNO 10.03	Be immune to magnetic fields from normal magnets, issue alert when stronger magnets are used	Requirement to comply with BS EN 50470 standard, adds no extra cost.	None
DNO 04.07	Configurable parameters to support extreme under or over voltage detection	Simply configurable diagnostic thresholds	Included on DNO 04.12
DNO 04.14	Configurable to disable supply if extreme under or over voltage detected	Is an 'on event>take action' requirement, similar to zero balance for credit, or detecting cover removal.	None directly. Requirement for remote meter configuration to set thresholds
DNO 02.10 (optional)	Support temperature sensing in an external device - i.e. connector block	Adds to physical components hence could add to overall cost of metering system in a home	As for DNO 02.11
DNO 04.05	Configurable to provide average, min and max voltage on demand	Linked to other voltage measurement and storage requirements	Included on DNO 04.12
DNO 08.01	The meter shall be configurable to identify GSS (>18 hour) failures	Is a simple diagnostic event linked to loss of supply	Included on DNO 05.02
DNO 08.02	Configurable to detect and record GSS failures	Is linked to detecting loss of supply	Included on DNO 05.02

4 Benefit Analysis

4.1 Benefit Analysis for CBA Model

This section summarises the Benefit Analysis for the CBA Model within the ENA smart metering CBA project and has used some sample data provided by a subset of network businesses which has been scaled up to estimate the total GB benefits.

The detailed benefit calculations and assumptions can be found in the ENA Incremental CBA spreadsheet.

4.1.1 Benefit Assumptions

Engage, with some sample data from a subset of network businesses has collated and quantified a number of ENA benefits that can be attributed to operational savings and the availability of better planning data that are associated with smart metering.

The benefits are based on a roll out that will deliver full smart metering by 2020 and uses customer numbers that include predicted growth.

The benefit areas considered were:

- Improvement in Quality of Supply
- Efficient Network Investment;
- Theft of Electricity; and
- Customer service.

4.1.2 Improvement in Quality of Supply

Within this benefit there were two areas that were considered, more effective /quicker identification of LV and HV network faults resulting in reduced labour costs and improved customer minutes lost (CML) performance.

Better identification of faults (labour savings) - This has been calculated by assuming that 80%[7] of faults are at the LV level and 10%[8] of these will provide an opportunity to reduce the labour cost. This has then been offset against the sample DNO customer base (due to data being available for labour costs) and then scaling for GB.

The total benefit across all DNO's is c£2.2m per annum once smart metering has been rolled out in 2020.

Better management of CML (IIS savings) – This has been calculated by assuming that the average £m / CML incentive rate of £348k[9] per annum applies for each DNO and there will be an assumed 0.4 minutes[10] reduction in CML.

[7] 80% of total faults as estimated from sample DNO data

[8] 10% of the 80% will provide an opportunity to reduce the labour costs as estimated from sample DNO data

[9] £348k average per annum IIS Rate as calculated using the DPCR 5 table 16.5 information

[10] 0.4 minutes reduction in CML as calculated from DNO sample data

The total benefit across all DNO's is c£2m per annum once smart metering has been rolled out in 2020.

4.1.3 Efficient Network Investment

The refinement of the planning process from the implementation of smart metering utilising the additional data available will help to minimise the cost of LV and HV network reinforcement. This benefit has been calculated by using the current investment costs of £6m per annum for the sample DNO HV and LV network and assuming that a) the current load growth will increase from 1% per annum to 2%[11] due to new sources of consumption (such as electric vehicles and heat pumps) and b) that the availability of smart metering date will result in a 5%[12] annual saving due to smart design.

The total benefit across all DNO's is c£4.4m per annum once smart metering has been rolled out in 2020.

This analysis does not assume any benefit associated with EHV network reinforcement due to the current availability of SCADA information on the EHV network.

The SEDG report for ENA "Benefits of Advanced Smart Metering for Demand Response based Control of Distribution Networks", highlights the potential avoided cost of HV and LV network reinforcement if smart metering can be used as an enabler for responsive demand. The report estimated the **potential avoided distribution networks reinforcement costs to be in the range of £0.5bn to £10bn**, depending on EV and heat pump penetration levels, the degree of responsiveness of the associated demand, and the range of network reinforcement solutions that might be required.

4.1.4 Theft of Electricity

Theft of electricity was also considered for inclusion in the CBA. However as DNOs suffer no direct loss of income from stolen units as their allowed revenues are no longer subject to a volume incentive, there is no lost revenue. There is a financial impact in terms of the losses incentive, however as the only way smart meters would reduce theft directly is through tamper proofing and as this is included in the SRSM benefits this has not been included within these benefits.

4.1.5 Customer Service

Whilst there are obvious customer service benefits by having additional information to hand and being able to react to outages quicker, to attribute a cost saving to these further analysis would have to be undertaken to identify the full benefits. Below are some of the potential customer service benefits:

- Enhance the customer experience of new connections and adding new equipment;
- Enhanced safety at the customers' premises (Auto-disconnection to make safe at meter); and

[11] 1% and 2% growth rate estimated from sample DNO data
[12] 5% annual saving estimated from sample DNO sample data

- Enhanced customer service (allowing checking of the premises that received planned outage notification; immediate notification during emergencies; improved fault identification).

4.1.6 Conclusion

In conclusion there are significant overall benefits from the implementation of smart metering for DNO's with **an estimated NPV value of c£50m from 2010 to 2032.**

4.2 ENA member functionality benefits in addition to benefits identified in the Government's impact assessment published in December 2009

This paper reviews Smart Meter benefits identified in the DECC Smart Metering Impact Assessment and identifies additional benefits arising from the ERA requirements.

4.2.1 Additional ENA Benefits Analysis

The aim of this paper is to highlight additional network related benefits of smart meter rollout in Great Britain over and above those identified in the DECC Smart Metering Impact Assessment[13]. The analysis compares the benefits already identified in DECC Smart Metering Impact Assessment with the benefits identified in ENA Smart Metering Use Cases document[14]. The outline of the DECC benefits have been extracted for information purposes and is available in Annex 1; the extract of ENA benefits for smart meters is available in Annex 2.

It is worthwhile to note that the two documents are written at different levels of detail, therefore often benefits relate to the same area but the detailed benefit identified appears to be different. We have used our best judgment to assess the level of overlap of the benefits between DECC and ENA where this overlap is not clear from the level of definition in the DECC IA.

Tables 1 and 2 below highlights the benefits that are above and beyond those identified in DECC impact analysis and those that partially overlap with DECC analysis. For simplicity the benefits are divided into categories thus summarising them within certain sector.

4.2.2 Summary of the ENA identified benefits over and above the DECC smart metering benefits

Table 1 – Electricity related smart metering benefits

ENA Benefit Category	ENA Benefit Description	Overlaps with DECC assessment
Reduction in cost to serve	1. Reduced cost to serve by moving away from letters (UC12), effective use of the DNO's workforce in outage management (UC13) due to the ability to correctly	✓ (this may be partly covered by DECC: includes benefits from

[13] DECC "Impact Assessment of a GB-wide smart meter roll out for the domestic sector", December 2009; Section F 3, p.24. Available at: http://www.decc.gov.uk/en/content/cms/consultations/smartmetering/smartmetering.aspx
[14] ENA "Smart Metering System Use Cases" – ENA-CR007-002-1.1. Available at: http://www.energynetworks.org/ena_energyfutures/ENACR007_002_1-1_UseCases_100412.pdf

ENA Benefit Category	ENA Benefit Description	Overlaps with DECC assessment
	determine the issue (UC14) and reduce DNO call-outs to attend premises due to dangerous conditions (UC18) 2. Informed network investment / intervention decisions resulting in reduced capital costs (UC 04) 3. Avoidance of unnecessary reinforcement or active network management costs due to enhanced assessment of capacity headroom (UC 02)	"Avoided meter reading" and "avoided site visit" – it is likely that these may be visits in addition to those identified in the DECC analysis in which case this benefit is additional; also customer service overheads – reduction in calls; remote avoided equipment upgrade costs)
Improvement in Quality of Supply and Compliance	1. Ability to identify the effectiveness of active network management or system balancing measures and thus being able to tailor them to gain suitable responses. (UC11) 2. Develop strategies to improve network performance (UC16) (e.g. more refined emergency load reduction / disconnection functionality (UC17)) 3. Reduce exposure to Guaranteed Standards of Performance failures (e.g. supply restoration exceeding 18 hrs (UC15); timescales for provision of LV connections (UC02); timescales for dealing with additional demand / generation enquiries (UC03)) 4. More auditable for outage notification (UC12) 5. Fewer customers affected by planned outages(UC17) 6. Improved restoration times for customers affected by unplanned outages (UC17) 7. Better management of Customer Interruption (CI) and Duration (Customer Minutes Lost (CML)) performance through earlier identification of masked faults (UC15) 8. Voltage level and power flow maintenance within the prescribed limits (UC08) (UC 09) 9. Allows identification and resolution of fault masking (UC15)	✓ (partly covered by DECC in "Losses" – reduction in distribution losses)
Efficient network investment	1. More informed, efficient and timely network investment (UC01) 2. Avoid or defer investment in reinforcement of the network (UC08,09)	✓ (partly covered in "Generation capacity investment" – shift to off-peak consumption)
Additional Demand/generation and new connections support	1. Faster, better informed responses to requests for additional demand / generation and new connections (UC 01) 2. Accurately determine the reinforcement or active network management requirements, together with the associated costs, to allow the proposed new demand / generation connections to be provided	✓ (partly covered by DECC, however DECC estimation needs update as microgenerators are to have meters)

ENA Benefit Category	ENA Benefit Description	Overlaps with DECC assessment
	(costs will include those funded by the user and the DNO) (UC02) and the associated costs with the increase in demand / generation at an existing connection point based on a sound understanding of the diversity between the new demand / generation and the existing network power flows, and hence the impact of the superimposed new demand / generation on the existing load cycle. (UC 04) 3. Higher levels of demand / generation to be connected to the network (UC 03) 4. Potentially reduced claims for damage to appliances (UC19) and avoided bad publicity associated with damage to appliances 5. Providing alternative balancing actions and sources of short term operating reserve, which are expected to increase with the growth of intermittent generation and connection of larger transmission connected generation, e.g. 1,800 MW units (UC10)	
Identification of network issues and forecasting of reinforcement need	1. Earlier identification of potential network stresses (i.e. caused by latent demand) – enabling mitigating interventions before thermal loading or statutory voltage transgressions occur (UC01) thus avoiding interruptions to customer supply and potentially damaged assets (UC05); maintain power flows and network voltages (UC07) 2. Improved forecasting of future reinforcement need (UC 01) 3. Improved identification of the root cause (for example a recent installation or change of use) (UC06) 4. Improved network load forecasting capability (UC 04) 5. Improved identification of increase in voltage quality issues (UC 06)	
Reduction in Theft	1. Reduced non-technical losses (by managing safety alarm) (UC18)	✓

Table 2 ENA Gas related benefits over and above DECC smart metering benefits

ENA Benefit Category	ENA Benefit Description	Overlaps with DECC assessment
Improvement in Quality of Supply and Compliance	1. Remove cost involved in identifying and establishing specific demand sites and obtaining and recording demand data (UC01) 2. Ability to update Smart Metering System with different parameters to meet future requirements (UC02) 3. Quicker restoration of gas supply after gas supply emergencies (UC 03)	✓ (partly covered by DECC: which includes benefits from "Avoided meter reading" and "avoided site visit"; also customer service overheads – reduction in calls; remote avoided equipment upgrade costs)
Efficient Network Investment	1. Better modelling which will lead to better investments resulting in more efficient investment (UC01)	
Customer Service improvement	1. Protection of the consumer (through ability to assist the emergency process (UC03))	

4.2.3 Summary

To sum up the following gas and electricity benefits are partially covered by both ENA and DECC:

- Effective use of the DNO's workforce – reduction in call-outs (DECC: avoided site visits). It, however, remains under question whether DECC analysis included reduction in call outs in cases of outage or other network related issues;
- Reduced cost to serve – moving away from letters, avoid unnecessary reinforcement, remove cost involved in identifying and establishing specific demand sites- (DECC: avoided meter readings, reduction in customer service overheads). It also remains under questions whether DECC impact assessment included networks related reinforcement;
- Reduction of technical and non-technical losses (i.e. thief) (DECC: reduction in distribution losses);
- Avoid or defer investment in reinforcement of the network (partly covered by DECC: "Generation capacity investment" – shift to off-peak consumption);
- Use of micro-generators (DECC covers benefits from micro-generators, however it does not take into account the requirement to install generation meters);
- The following benefits are above and beyond DECC benefits:
- Less network related intervention resulting in reduced capital costs;
- Reduced asset failure through better asset management;

- Improved network performance – voltage and power flow maintenance within limits, identification and resolution of faults, prevention of fault, early identification of network stresses;
- More auditable for outage notification;
- Better customer service: fewer customers affected by planned outages and smaller duration of planned outages;
- More informed network investment (potentially avoided network reinforcement);
- Better facilitation of demand/generation connections – quicker responses to requests for additional and new connections; precise determination of needed requirements to support the demand
- Reduction in claims for damage to appliances, thus avoided bad publicity;
- Support renewable generation; and
- Improved customer experience of new connections and adding new equipment.

4.3 Review of Imperial College and SEDG Report "Benefits of Advanced Smart Metering for Demand Response based Control of Distribution Networks" and Explanation of its Rationale for Cost Benefit Analysis

This section reviews macro-level benefits contained in the Imperial College and SEDG work ("Benefits of Advanced Smart Metering for Demand Response based Control of Distribution Networks") and explains how these could be used as rationale for cost benefit analysis.

4.3.1 High-level Outline of the Imperial College and SEDG report

The section below outlines the main points made in the report in order to identify the rationale for cost benefit analysis.

4.3.2 Aim of the report:

To estimate the benefits of future real-time distribution network control which incorporates real time demand response facilitated by smart metering infrastructure.

4.3.3 Methodology of the report:

To quantify the impact on the UK electricity distribution network caused by Electric Vehicles (EVs), Heat Pumps (HPs) and smart domestic appliances (SAs), and the benefits of using smart metering enabled Smart Grid capabilities to actively manage these networks, the work compared two approaches: present 'unconstrained access' network control paradigm ("Business as Usual") and an active network control approach based on optimised demand side response.

Different EVs and HPs penetration scenarios were considered, namely, 10%, 25%, 50%, 75% and 100% penetration.

The analysis is based on diversified household load profiles and average national driving patterns applied to all local networks. Hourly time resolution was adopted due to data availability.

4.3.4 Scope of the report:

The benefits quantified are focussed on distribution networks and the report does not attempt to quantify the benefits for transmission and generation infrastructure arising from a Smart Grid approach to managing the addition electrical demand.

The analysis investigated the boundaries of possible outcomes over a full range of scenarios. This work also recognised, but does not quantify, that there may be some synergies between the reinforcement requirements in the BaU approach and the distribution network asset replacements that would be needed due to normal aging of equipment, which could represent an opportunity to carry out a strategic asset replacement of higher capacity in anticipation of higher network loading (this could potentially reduce the benefits of active distribution management facilitated by an appropriate smart metering functionality).

The following benefits were also recognised but not quantified in this analysis:

- benefits from reduced generation capacity requirements;
- provision of flexibility and contribution to national and regional system balancing and enhanced utilisation of the transmission network;
- improved outage management
- better investment optimisation; and
- greater capacity to accommodate low-carbon generation and load growth.

Moreover, the inclusion of real-time management ability facilitated by smart meters will increase the ability of the system to accommodate future network development; incorporate vehicle-to-grid applications; and enable DNOs to contribute to the national demand-supply residual balancing function and improve real-time management of the GB transmission system.

4.3.5 Assumptions within the report:

Some of the key assumptions of new demand included:

Regarding EVs, average national driving patterns are applied to all local distribution networks.

Regarding HPs, Grade A insulation levels in dwellings heated by HPs with storage.

Regarding Smart appliances, the analysis focused on three types of wet appliances: washing machines (WM), dishwashers (DW); and washing machines with tumble dryers (WM+TD).

The analysis considered three representative distribution networks (urban, semi urban/rural and rural).

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4.3.6 Result of the report:

The analysis demonstrated that optimising responsive demand has the potential to reduce the system peak and the need for system reinforcement by a very considerable amount even at relatively low EV and HP penetration levels.

Additionally, considering that this analysis is based on fixed, average load patterns, and it does not capture the variability of particularly lumpy loads, the benefits of active network control are underestimated.

The quantified benefits in this analysis are reflected in terms of avoided electricity charges associated with network reinforcement of adopting an active network control approach as enabled by smart meter installation.

4.3.7 Quantified benefits:

The analysis shows that the value in NPV terms of changing the network control paradigm (using smart meters) ranges between approximately £0.5bn and £10bn across the scenarios considered.

Table 1 below is a summary of the costs and benefits identified by the analysis. It can be noticed that the total network costs are dominated by the low voltage networks.

Table 1: GB NPV of network reinforcement costs for two network control approaches and the associated value of smart meter-enabled active control

Scenarios	NPV costs LV (£bn)		NPV costs HV (£bn)		NPV Value of Smart (£bn)
	BaU	Smart	BaU	Smart	
SCEN 10%	0.75 - 2.48	0.30 - 0.98	0.06 - 0.20	0.03 - 0.08	0.48 - 1.62
SCEN 25%	1.90 - 6.26	0.70 - 2.32	0.20 - 0.66	0.04 - 0.13	1.36 – 4.47
SCEN 50%	3.76 - 12.4	1.48 - 4.88	0.30 - 1.00	0.13 - 0.42	2.45 – 8.10
SCEN 75%	5.08 - 16.72	2.47 - 8.12	0.34 - 1.11	0.22 - 0.71	2.73 – 9.00
SCEN 100%	5.85 - 19.27	2.91 - 9.59	0.37 - 1.21	0.26 - 0.85	3.05 – 10.04

The NPV value of an active distribution grid facilitated through real time demand response is estimated by comparing the NPV cost of BaU and Smart. This can therefore be used to present quantified benefits of active demand management for the distribution networks in terms of avoided distribution reinforcement costs. At overall penetration levels of up to 50%, the relative benefits of a Smart Meter rollout scenario over the BaU scenario is particularly high when compared to NPV BaU costs.

4.3.8 Rationale for Cost Benefit Analysis

From the information above it can be concluded that the report "Benefits of Advanced Smart Metering for Demand Response based Control of Distribution Networks" prepared by SEDG and Imperial College on behalf of the Energy Networks Association can be used to estimate quantified distribution network operator related benefits for particular smart meter functionality, namely, demand side response using communication infrastructure between the smart metering system and EVs, HPs, and smart domestic appliances.

The benefits in the above mentioned report are presented in terms of difference in network reinforcement costs to accommodate EVs, HPs and smart domestic appliances between the Business as Usual network and smart meter enabled network. Therefore by assuming a certain penetration scenario of the smart appliances, EVs and HPs, it is possible to present a quantified benefit of demand side response for distribution networks.

This work can be used when highlighting smart metering benefits within demand response functionality. The smart meter demand response benefit is presented in terms of avoided distribution networks reinforcement costs, which, depending on penetration level, varies between £0.5bn to around £10bn.

5 Appendix A: Detailed Requirements Comparison

ENA Ref	Requirement	SRSM Coverage	Type	Notes
COM 01.01	Secure 2 Way Comms between Metering System and Authorised Party	B.COM.012	Joint	
COM 01.05	WAN interface will allow alternative & future communications to be utilized	Yes	Joint	Requirement relates to firmware upgrades, and to use of standards and regulated development. Covered by ERA requirements for both, and supplemented by ERA requirement for a separate Communications Box
COM 01.02	Communicate meter interval readings configured by Authorised Parties	B.COM.005	Joint	
COM 01.03	Send Import and Export Data on Demand	B.COM.006	Joint	
COM 01.04	Send cumulative import/export data within time schedules	B.COM.005	Joint	
COM 02.01	Secure 2 Way Comms between Metering System and Local Devices	B.COM.013	Joint	
COM 02.02	HAN to support messaging between meter and other devices connected to the HAN	B.COM.013	Joint	
COM 02.03	LAN interface will allow alternative and future communications options to be utilized	NA	Note	SRSM makes no distinction between LAN and HAN. Covered by general reference to Local Communications. At moment, cannot presuppose the national technical architectural solution as HAN/LAN or other
COM 02.04	HAN interface will allow alternative and future communications options to be utilized		Joint	Both specifications require 'upgradeable' HAN solutions. This is not the same as WAN as it could involve devices outside of the control of the system. Upgradeable firmware and standards still apply here
DNO 01.01	Meter to hold location information		ENA	Referenced in 2007 SMOF as a possible data item to be held by meter. Remains simply a data item
DNO 01.02	Upon installation, self register and issue a signal to the grid		ENA	Presupposes installation processes - is only one of a number of approaches to smart metering installation - requirement should be for smart meter installation data to support ENA business

ENA Ref	Requirement	SRSM Coverage	Type	Notes
				processes – adds no costs
DNO 01.03	Configurable to automatically update the system to adapt to grid network system changes		ENA	Relates to network impact of installation of new demand/generation connections - should be deliverable by software and HAN connection
DNO 02.01	Measure import/export active energy	B.ELE.012	Joint	
DNO 02.02	Measure import/export reactive energy		ENA	Extra data to measure, store and communicate
DNO 04.04	Record Half Hourly average RMS voltages		ENA	Extra data to measure, store and communicate
DNO 02.06	Record and store energy values for import export for at least 3 months	B.COM.004	Joint (Note)	ENA requirement is for a specific time period, with no detail of what might be recorded. ERA illustrate memory scale through half hourly data intervals
DNO 04.11	Meter will store voltage profile data for 3 months		ENA	Extra data to measure, store and communicate
DNO 04.12	Meter will store a specified minimum number of Under and Over voltage events		ENA	Minimum not specified
DNO 02.04	Capable of calculating and reporting power factors		ENA	Extra data to measure, store and communicate
DNO 02.05	Capable of deriving and recording maximum kVA for import export for polyphase meters	EPM Variant	Joint	Only applies to polyphase supplies
DNO 04.06	Provide power quality information as configured and on demand		ENA	Is a generic communication requirement, but could add cost if detailed power quality information is required
DNO 04.13	Store a configurable minimum number of power quality event recordings		ENA	Minimum not specified
DNO 04.15	Record power quality events		ENA	Extra data to measure, store and communicate
DNO 03.01	Operate as a multi-rate meter capable of supporting ToU, Time of Day, Critical Peak, Dynamic Pricing	B.COM.007	Joint (Note)	Dynamic pricing isn't part of the SRSM specification
DNO 03.02	Support configurable combination of register types	B.COM.011	Joint	
DNO 06.01	Support remote load management via communication with relevant load management devices and generation	B.COM.013	Joint	Is effectively a specific requirement of a HAN network to support remote operation of appliances/microgen
DNO 06.02	Support basic load control functions		ENA	Looking to meter to automatically control load/devices within premises via HAN or by meter itself

ENA Ref	Requirement	SRSM Coverage	Type	Notes
DNO 06.03	Support Emergency Override Control		ENA	Is prioritised scheduling of load control events
DNO 07.01	Support Microgeneration via communication with generation meters	B.COM.013	Joint	Although not explicit in ERA, this is utilisation of the HAN in a specific business context
DNO 06.04	Configurable to enable and disable Meter Load Limit Exceeding Switching	B.ELE.005 B.ELE.022	Joint	ENA written as a compound requirement to include a switch to enable/disable and to support a load threshold
DNO 04.01	Detect under and over voltage levels		ENA	
DNO 04.08	Issue an alarm when Over or Under Voltage is detected - configurable thresholds		ENA	Is an alert to a specified party upon the incidence of specific circumstances? Common requirement for both ERA and ENA
DNO 06.05	Display outage notifications to customers	B.COM.044	Joint (Note)	ENA looking for multiple language support - the meter (and IHD) will display whatever is sent to it - it will not be capable of translating messages.
DNO 04.03	Support remote energisation status check		ENA	Should be simple to measure
DNO 05.01	Detect loss of supply		ENA	Should be simple to measure
DNO 05.03	Issue alarm on detection of loss of supply.		ENA	ENA requirement is very specific - alert to be sent 3 to 5 minutes after loss of supply. Not specific how meter does this with no power
DNO 05.05	Issue notification of when loss of supply restored		ENA	Diagnostic event - priority of issue of notification not clear from ENA requirements
DNO 05.02	Store loss of supply information for configured period		ENA	Store loss of supply information for configured period
DNO 08.03	Will store loss of supply over 18 hours for at least 3 months		ENA	Store loss of supply information for configured period
DNO 05.04	Communicate loss of supply duration information		ENA	Similar to DNO 05.05, but a different data set for the alert message
DNO 02.11	In Built Temperature Sensor (optional)		Note	Optional requirements are difficult to assess
DNO 04.02	Detect reverse polarity		ENA	Requires additional hardware to detect
DNO 04.10	Issue reverse polarity alarm		ENA	Is a diagnostic event/message - similar to those in SRSM, should attract no additional cost
DNO 10.01	Detect physical tamper events	B.COM.003	Joint (Note)	Both sets of requirements need much more detailed specification
DNO	Be immune to magnetic		ENA	Is a specific security

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ENA Ref	Requirement	SRSM Coverage	Type	Notes
10.03	fields from normal magnets, issue alert when stronger magnets are used		(Note)	requirement - similar, but more specific than SRSM B.COM.029
DNO 04.07	Configurable parameters to support extreme under or over voltage detection		ENA	Simply configurable diagnostic thresholds
DNO 04.14	Configurable to disable supply if extreme under or over voltage detected		ENA	Is an 'on event>take action' requirement, similar to zero balance for credit, or detecting cover removal.
DNO 02.07	Support configurable meter reading schedules	B.COM.005	Joint	
DNO 02.08	Provide configurable on demand information	Many	Joint	Is a generic requirement for data
DNO 02.10	Support temperature sensing in an external device - i.e. connector block		ENA	Adds to physical components = could add cost
DNO 02.12	Configurable to notify Authorised Party of a meter event	Many	Joint	Is a generic requirement for messaging
DNO 04.05	Configurable to provide average, min and max voltage on demand		ENA	Linked to other voltage measurement and storage requirements
DNO 11.01	Capable of remote accurate synchronization	B.COM.052 B.COM.054	Joint	Specifically linked to Supplier requirement
DNO 08.01	The meter shall be configurable to identify GSS (>18 hour) failures		ENA	Is a simple diagnostic event linked to loss of supply
DNO 08.02	Configurable to detect and record GSS failures		ENA	Is linked to detecting loss of supply
GDN 02.06	Store consumption for configurable time periods for up to 3 months	B.COM.004	Joint	
GDN 02.03	Configurable to receive CV and correction values from Authorised Party	B.GAS.014	Joint	
GDN 02.05	Configure to use CV from specific start date and time		ENA	Similar to tariffs and other items - can be scheduled for application from a point in the future
GDN 02.07	Measure and Store calorific values within meter (optional)		Note	Optional requirement, subject to cost. Possibly warrants further detailed discussion to understand the possibilities and implications
GDN 02.01	Record meter reads at configurable time intervals	B.COM.004	Joint	
GDN 02.02	Configurable to upload reads to central storage facility at defined times		Joint	ENA requirement, although described differently, is equivalent to SRSM read requirements
GDN 05.06	Configurable valve	B.GAS.004	Joint	
GDN 02.04	Use calorific values to calculate energy values	B.GAS.014	Joint	

ENA Ref	Requirement	SRSM Coverage	Type	Notes
GDN 05.05	Positive response from meter where a valve closure has been requested		ENA	Difficult to prove that a meter can guarantee the valve has actually closed as requested
GDN 08.03	Display scheduled gas disconnection messages to customers	B.COM.044	Joint	Is a specific 'Message to Customer'
GDN 08.01	Visual display of time remaining before automatic valve operation of open or close		ENA	Different 'type' of requirement from SRSM ones, but should be possible utilising the hardware
GDN 08.02	Display status of valve		ENA	Similar to a number of SRSM requirements to display status or mode of operation etc.

5.1.1 Version History

Version	Date	Note
0.1	17.5.2010	Initial Draft
0.2	18.5.2010	Update following peer reviews
0.3	22.5.2010	Project Manager review
0.4	24.5.2010	Update following review by BEAMA
0.5	25.5.2010	Update
0.6	25.5.2010	Update following review
0.7	03.6.2010	Update following comments from Alan Creighton and discussions with BEAMA
0.9	14.06.2010	Update following further comment from ENA
0.10	16.06.2010	Update following discussion with BEAMA
1	24.06.2010	Baseline version for release
1	28.06.2010	Minor wording update to baseline

6 Annex 1 - Summary of DECC listed smart metering benefits[15]

Area of benefit	Estimated DECC Benefits and notes	Overlap with ENA benefits
Consumer benefits		
Energy demand reduction	2.8% for electricity (credit and PPM); 2% for gas credit and 0.5% for gas PPM (sensitivity analysis: in the higher benefits scenario: 4% for electricity (credit and PPM), 3% for gas credit and 1% for gas PPM; in the lower benefits scenario: 1.5% for electricity (credit and PPM), 1% for gas credit and 0.3% for gas PPM.	
Energy demand shift	DECC assumes a 20% take up by consumers of the Time of Use (ToU) tariff (in addition to the existing group using this option) and a resulting overall 3% electricity bill reduction and 5% peak use reduction for these customers; sensitivities are made on the take up at 0% and 40%.	✓ (partly touches on effect from tariffs UC08)
Valuing avoided costs of carbon from energy savings	For electricity, reductions in electricity use will mean the UK purchasing fewer EU ETS allowances and this saving is assimilated as a benefit. This accounts for Present Value (PV) £0.4bn to £0.5bn. For gas, this corresponds to approximately PV £0.9bn.	
Reduction in carbon emissions	£2.6bn savings for electricity and £1.9bn savings for gas	
Microgeneration	Using the assumption that there will be around 1 million of microgeneration devices by 2020 the saving is estimated to be £0.12 per annum per meter (assuming a separate meter is not needed and its installation cost).	✓ (partly covers new connections; however it was agreed that microgeneration will have meters)
Supplier benefits		
Meter reading	"Avoided meter reading" will bring in benefit (cost savings) of £6 per (credit) meter per year. Another benefit linked to meter reading – "avoided site visit" has also been included. These are avoided special visits to read meters or ad hoc safety-related inspection visits outside the normal cycle. Reductions in the requirements for these visits are assumed to give a benefit of £0.75 per meter per year. Any residual ESQCR requirement for safety visits could increase costs.	✓
Customer service overheads	Cost saving is estimated to be £2.20 per meter per year (£1.88 for reduced inbound enquiries and £0.32 for reduced customer service overheads). The assumption is based on previous supplier estimates that inbound call volumes could fall by around 30% producing a 20% saving in call centre overheads.	
Remote switching and disconnection	The direct benefits associated with these capabilities are the avoided site visits and equipment upgrade costs. These are captured in the debt management and in the pre payment cost to serve savings. A further benefit of £0.5 per credit meter per year is also included for the benefits of being able to remotely disconnect those consumers.	✓
Pre payment cost to serve	The additional cost to serve consumers with PPMs is £30 for electricity and £40 for gas. The introduction of smart metering would reduce (but not remove all) those additional costs. The level of savings attributed to smart meters is 40%, representing an annual saving of £12 for each electricity PPM and £16 for each gas PPM.	

[15] As taken from DECC Summary paper titled: "Impact Assessment of a GB-wide smart meter roll out for the domestic sector" (dated: December 2009) [Available online at: http://www.decc.gov.uk/en/content/cms/consultations/smart_metering/smart_metering.aspx]

Area of benefit	Estimated DECC Benefits and notes	Overlap with ENA benefits
Debt management	The benefit assumed is £2.20 per meter per year, which reflects reduced inquiries related to change of occupier and change of supplier. Suppliers estimate that a 30% fall in inbound calls volume could result in 20% savings in call centres overheads.	
Theft	The implementation of smart metering could reveal existing theft and allow suppliers to combat it better. It is suggested that this could reduce theft by 20-33% equivalent to £0.27 to £0.85 per meter per year. The assumption of a reduction of 10% or c. £0.2 per meter per year is used by DECC.	✓
Losses (Distribution)	It is assumed that smart meters will facilitate some reduction in losses and that the benefits per meter per year will be £0.5 for electricity and £0.1 to £0.2 for gas.	✓
Switching Savings	Assumed savings of £100m per year.	
Generation capacity investment	The assumed consumer energy demand shift to off-peak load could realise savings in investment in generation capacity. DECC assumes that the cost of additional investment in generation capacity is of £600 per additional kw of investment. If consumers shift to off-peak consumption some of the investment in generation capacity will be unnecessary, therefore realising savings to energy suppliers.	✓
Intangible benefits		
Competition	Smart meters should enhance the operation of the competitive market by improving performance and the consumer experience, encouraging suppliers' (and others) innovation and consumer participation.	
Longer term network management and demand-side load shifting	It is difficult to quantify what the benefits of these changes (often described as Smart Grids) would be or the other opportunities which may flow from them, and further work is being undertaken to understand them. Smart metering could facilitate responses to future changes in energy demand (through, for example a greater take up of electric cars or the adoption of demand-side management approaches) which will entail more proactive management and pricing. In addition smart meters provide a platform for more effective management of the future grid where energy will come from a variety of sources – including some which may be more intermittent – and generation becomes more decentralised. There are potential benefits here from reduced overall demand and the smoothing of demand between peaks. In the longer term benefits may also be identified in this area which may contribute on security of supply objectives. With additional renewable electricity being delivered predominantly by wind generation back-up generation is required to maintain security of supply. Smart metering with automated controls to switch load would reduce the need to bring on-line conventional generation and reduce the need for investment in backup generation.	✓ (please see the section titled: ENA additional benefits)

7 Annex 2 – ENA Use Case Analysis and benefit outline

Table 1 – Electricity smart metering benefits for networks

Benefit	Business Benefit
Assess Network Performance	
UC 01 - Monitor Power Flows and Voltage Levels to Identify Thermal Capacity and Voltage Headroom	• Higher utilisation / more efficient use of existing networks • More informed, efficient and timely network investment • Faster better informed responses to requests for additional demand / generation and new connections • Earlier identification of potential network stresses – enabling mitigating interventions before thermal loading or statutory voltage transgressions occur • Improved forecasting of future reinforcement need
UC 02 – Determine network impact of proposed demand/generation connections	• The information enables DNOs to comply with Guaranteed Standards of Performance timescales for provision of LV connections • Enables DNOs to accurately determine the reinforcement or active network management requirements, together with the associated costs, to allow the proposed new demand / generation connections to be provided (costs will include those funded by the user and the DNO) • Avoidance of unnecessary reinforcement or active network management costs due to enhanced assessment of capacity headroom • Enables DNOs to accurately determine the reinforcement or active network management requirements, together with the associated costs, to allow the proposed new connection to be connected to the network (costs will include those funded by the user and the DNO) • Enhance the customer experience of new connections
UC 03 – Determine network impact of proposed increases in demand/generation at existing connection points	• The information enables DNOs to comply with Guaranteed Standards of Performance timescales for dealing with additional demand / generation enquiries • Enables DNOs to accurately determine the reinforcement or active network management requirements, together with the associated costs, to allow the proposed demand / generation to be connected to the network (costs will include those funded by the user and the DNO) • Avoidance of unnecessary reinforcement or active network management costs due to enhanced assessment of capacity

Benefit	Business Benefit
	headroom • Enhanced data from Smart Metering System permits higher levels of demand / generation to be connected to the network • Enhance the customer experience of adding new equipment
UC 04 – Monitor demand and generation profiles for network load forecasting	• Improved network load forecasting capability • Informed network investment / intervention decisions resulting in reduced capital costs • Enables DNOs to accurately determine the reinforcement or active network management requirements, together with the associated costs, associated with the increase in demand / generation at an existing connection point based on a sound understanding of the diversity between the new demand / generation and the existing network power flows, and hence the impact of the superimposed new demand / generation on the existing load cycle.
UC 05 – Determine Latent Demand due to Embedded Generation	The benefit of this approach is that the DNO will be able to better understand and manage the risks associated with latent demand. If the latent demand is not understood, then in certain network conditions there will be a risk of overloading the circuits resulting in interruptions to customer supplies and potentially damaged assets.
UC 06 – Identify Voltage Quality Issues	• The presence of excessive voltage fluctuations determined at an early stage improving the chances of identifying the root cause (for example a recent installation or change of use) and securing agreement by the customer to rectify the issue • Early identification and resolution of the issue would provide affected customers with earlier relief from the nuisance of voltage flicker • Early identification of any general increase in voltage quality issues that might require a change in the process surrounding connections of disturbing loads and/or to the standards governing equipment (such as heat pumps) so that the issue is designed-out.
Actively manage networks	
UC 07 – Collect data for active network management	This use case allows Distribution Network Operators to identify parts of the network where rectifying actions are needed in real time to maintain appropriate power flows and network voltages. The use of Smart Metering Systems allows increased monitoring so that the requirement for real time interventions can be identified. Potential benefits include: • Increased efficiency of network operation • Reduced need for network reinforcement

Benefit	Business Benefit
	• Improved reliability and quality of supply.
UC 08 – Active management of Network Voltage	• efficiently ensuring that voltages on the distribution network are maintained at all times within the prescribed limits • helping to avoid or defer investment in reinforcement of the network
UC 09 – Perform active management of network power flow	• efficiently ensuring that power flows on the distribution network are maintained at all times within the prescribed limits • helping to avoid or defer investment in reinforcement of the network
System Balancing	
UC 10 – Perform System Balancing	• Providing alternative balancing actions and sources of short term operating reserve, which are expected to increase with the growth of intermittent generation and connection of larger transmission connected generation, e.g. 1,800 MW units
UC 11 – Check effectiveness of active network management / system balancing measures	• This use case allows Network Operators to identify the effectiveness of active network management or system balancing measures and thus to be able to tailor them to gain suitable responses.
Actively manage network – planned and unplanned outages	
UC 12 – Notify consumer of planned outage	• Reduced cost to serve by moving away from letters • More auditable • Allows checking of the premises that have received the notification • Allows immediate notification during emergencies • Enhanced Customer Service
UC 13 – Query meter energisation status to determine outage source and location	• Make more effective use of the DNO's workforce, thereby reducing the cost to serve • Improve fault identification and location times thus reducing outage durations and hence enhancing the customer experience • Rapidly and proactively identifying outages affecting vulnerable customers (e.g. those reliant on artificial ventilators or dialysis machines)
UC 14 – Send alarm to DNO during network outage	The DNO will immediately be aware of a network fault, and the extent of the fault, enabling the correct action to be determined immediately. It will also avoid the despatch of the wrong type of operator due to an incorrect assessment as to the extent of the fault. The information will be used to determine the requisite number of staff to be dispatched to the appropriate location to resolve the fault (if a site visit is required), thereby reducing the time taken to locate and repair the fault and so: • Make more effective use of the DNO's workforce, thereby

Benefit	Business Benefit
	reducing the cost to serve • Avoid costs of abortive visits by inappropriate staff being unable to resolve the problem because the nature of the fault has not been correctly established before they are dispatched • Improve fault identification and location times thus reducing outage durations and hence enhancing the customer experience • Rapidly and proactively identifying outages affecting vulnerable customers (e.g. those reliant on artificial ventilators or dialysis machines) • DNOs are rapidly informed of outages – often before the Consumer notices • Unlike in Use Case 13 the DNO is sure that an outage is occurring rather than it potentially being a communications failure.
UC 15 – Verify restoration of supplies after outage	• Allows identification and resolution of fault masking • Reducing outage durations, thereby enhancing the customer experience • Positive confirmation of supply restoration, enhancing the customer experience • Better management of Customer Interruption (CI) and Duration (Customer Minutes Lost (CML)) performance through earlier identification of masked faults • Reduce exposure to Guaranteed Standards of Performance failures (e.g. supply restoration exceeding 18 hrs) • Reduced cost to serve through more efficient usage and deployment of field staff • Enhanced customer experience as DNOs will be confident that supplies have been restored without disturbing customers
UC 16 – Regulatory reporting of outages	With this information stored within the Smart Metering System, Distribution Network Operators can retrieve it whenever they need to create a report or conduct analysis of network quality of supply performance, e.g. the number of interruptions, customer minutes lost, Guaranteed Standard of Service failures, etc. The information could also ultimately be used to set up an automated payment system to automatically deliver Guaranteed Standard of Service payments to eligible Consumers. However, to be fully effective this will require phase connectivity of each Smart Meter to be identified, either during installation or as an inherent facility provided by the LAN (for example PLC would enable Smart Meter phase connectivity to be positively identified at the Data Concentrator). It will also enable Distribution Network Operators to analyse the time it takes to resolve outages and develop strategies to improve their

Benefit	Business Benefit
	performance.
UC 17 – Restore and maintain supply during outages	• Fewer customers affected by planned outages • Improved restoration times for customers affected by unplanned outages • Improved customer experience • Improved overall quality of supply performance • More refined emergency load reduction / disconnection functionality
Manage safety issues	
UC 18 – Manage meter safety alarm	• Reduced non-technical losses • Enhanced safety at the customers' premises • Reduce DNO call-outs to attend premises due to dangerous conditions • Automatic cut-off on detection of dangerous conditions prevents risk to Consumers
UC 19 – Manage extreme voltage at meter	• Automatic DNO notification of extremes of voltage • Auto-disconnection to make safe at meter • Reduced safety related risk to Consumer and premises • Potentially reduced claims for damage to appliances • Avoided bad publicity associated with damage to appliances
Support network activities	
UC 20 – Configure Smart Metering System	• Enables other described use cases to occur

Table 2 – Gas smart metering benefits for networks

Benefit	Business Benefit
UC 01 – Gather information for planning	• Improved Optimisation of Network • Better data will lead to better modelling which will lead to better investments resulting in more efficient investment and greater security of supply • Remove cost involved in identifying and establishing specific demand sites and obtaining and recording demand data
UC 02 – Configure gas smart metering system	• Ability to update Smart Metering System with different parameters to meet future requirements and supports the provision of data under Use Case 01.
UC 03 – Disable supply of gas by	• Ability to assist the emergency process to add further protection

Benefit	Business Benefit
GDN	to the consumer • Enables quicker restoration of gas supply after gas supply emergencies
UC 04 – Display Messages from GDN	• Ability to communicate key information to consumers in addition to existing processes • Ensure alignment between gas and electricity smart metering systems on the assumption that consumers would expect comparable benefits from any smart meter installation whether gas or electric.