

## **Smart metering subgroup – Smart Meters and Losses Incentive**

### **TOR (iv) – Losses**

#### ***a. Assess the use of smart meter data for modelling and measuring losses.***

In assessing the measurement of losses there are a number of methodologies that can be used most of which utilise the capability of smart meters to record half-hourly consumption data. A number of these approaches are outlined briefly below:

##### **1. Gross volume assessment**

This is a simple count of the total number of units of energy delivered into the distribution network from NG interfaces, interconnectors and embedded generators minus metered outflows to customers.

Sum of network energy in-feeds – sum of outgoing energy = technical & non-technical losses

In assessing energy in, there are a number of unmetered flows such as cross boundary DNO feeders. Similarly there are a number of unmetered outflows such as unmetered supplies, illegal abstraction, IDNO networks and again cross boundary feeders.

In order to measure and sum all of the useful energy exiting the network, the following sources would need to be captured:

- The energy imported by domestic and small enterprise customers demand – following the full scale national deployment of smart metering equipment, half-hourly resolution data will be available for a large population of these connections. There will however, be some customers who decline to have a smart meter and hence this resolution of data will not be universally available. There is a risk that if large number of customers decline smart meters all HH based methods would be jeopardised.
- The energy imported by larger, non-half-hourly metered customers (e.g. profile classes 5-8). For these customers, half-hourly or greater resolution import data is not currently available to DNOs but is available to suppliers.
- The energy imported by large industrial & commercial customers with existing half-hourly metering. This data is currently available to the DNO via the existing settlement data flows.
- The energy imported by un-metered supplies such as street lighting and public street furniture which relies on estimated consumption based on local street lighting authority or Highways Agency equipment inventories – there is no actual recorded consumption data for these connections and there are no plans to introduce further monitoring or metering. It is however evident that energy efficiency initiatives such as lighting switching regimes are changing usage patterns and further work may be necessary to define representative profiles.

The primary issue with this approach is that whilst the balance of the input minus output does contain losses, any change produced as a result of initiatives is likely to be extremely small versus the quantum of the balance. The risk with such a methodology is that the natural changes in the level of losses year on year due to say variations in demand levels may be significantly higher than the delta delivered by the initiative.

##### **2. Bottom out model**

In this methodology the metered flows out of any given part of the network are known via smart meters (and other sources as detailed above and hence the quantum of technical

losses arising from these flows can be derived using a load flow model of the relevant network.

This approach does not reconcile outputs to inputs and hence ignores unmetered supplies, abstraction etc. It does however allow the benefit of an initiative on a given network to be quantified with relative accuracy.

It is of note that the modelled output is likely to underestimate the benefit; as actual power flows will tend to be higher than derived flows due to the presence of the unmetered elements.

### **3. Load allocation model**

In this methodology all known energy flows are used to allocate load within a total network model (or indeed a sub set of such a model eg by GSP). This is similar to the Bottom out model being driven by SM data, however unmetered power abstraction points are represented by assumed energy flows. For example public lighting supply policy flows can be included based on MIC and assumed load profiles. Issues such as theft can be incorporated by scaling factors and all energy flows can be reconciled against known scada power flows to reconcile the model against the known demand by half hour period.

Having allocated all known demand, the standard power flow analysis can then be used to calculate per feeder losses and total losses against any desired initiative. Whilst this approach has the advantage of modelling the entire system to allow comparison of the benefit of a given initiative in all possible locations, there is a high dependency on data and a significant computational overhead. For example if every half hour is to be modelled – 17,500 readings per customer per annum. For ENWL that would be 42 billion readings and a huge number of studies. This is being looked at by Sustainable Energy in Bristol however the big data issues are significant.

### **4. Representative network model.**

An alternate approach is to use SM data to determine a representative load distribution curve<sup>1</sup> for each feeder type and the associated peak demand. SM data can be used as the basis for a detailed analysis of the power flows on each feeder type and all feeders can be can have a type allocation. The type model analysis can be used to assess initiative benefits and the system benefit scaled using the distribution of feeder types.

This methodology requires far less data and allows a representative approximation to the likely benefits. The derivation of representative feeder types is a logical extension of the recent smart grid forum Transform approach.

For all variants, for the purpose of the baseline, unmetered supplies can be assumed as either noise or applied as a common uplift based on known connections by post code. Theft etc could be ignored – for this purpose anyway.

IDNOs and cross boundary feeders could be enabled by the exchange of SM data between relevant parties. The absence of arrangements to make such data readily available acts as a potential barrier. It is considered that a DCUSA sub-group could potentially be tasked with exploring options to facilitate sharing / obtaining information between parties.

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<sup>1</sup> Note the proposal here would be to sample a small number of MPANs per feeder by type – CAT 1 -4 and determine an indicative load profile. Across a statistically representative sample of similar feeders ; in terms of MPAN class population / density etc~ 2 – 5% we would validate this load profile and then use this for all such feeder types. This would only be modified where there where known LCT connections such as PV, HP EV etc. In such instances the load profiles would be

It is critical to note that the current FIT default position is that G83 generators are assumed to export 50% of the electricity produced. This assumption is purely for the purposes of determining payments and in no way represents a reasonable estimate of actual energy exported which (for rooftop solar PV) will depend on the number and capacity of solar panels installed and the electricity consumed at the property. It follows that energy actually exported will vary significantly across seasons. For an ongoing overall losses monitoring regime, actual export volumes are needed and post SM roll out will be available.

Options 2, 3 and 4 allow the DNO to model of the quantum of 'measurable' losses and their distribution across the network mapped down to LV feeder level. For 2 and 4, the DNO does not need to have a load flow model of their HV and LV systems. This is a significant advantage as not all will have this capability. However the inherent approximations whilst convenient move us further away from reality at the micro level.

Finally all of these approaches are subject to five factors which combine to create inherent sensitivities in the accuracy of the modelling:

1. The time period over which the modelling is conducted, which may include network reconfiguration events due to say outages or connections. This may necessitate a considerable volume of data cleanse work particularly for scada solutions although arguably less so for the gross value approach.
2. The accuracy of all metering devices<sup>i</sup>
3. The volume of unmetered supplies
4. The inherent errors arising from a lack of detailed phase connectivity modelling.
5. The unknown relative proportionality of technical and non technical losses.

It can be argued that provided the modelling assumptions and methodology are common to all DNOs, then this will act to normalise out the inherent inaccuracies and provide a common base for comparison. It is also probably true to say that a number of the options can be combined to benefit customers for example use of the gross volume model to identify target networks and then use of the bottom out approach to identify specific circuits for intervention.

**b. Produce options for how smart metering data might be used to develop an output based losses incentive for ED2.**

In understand the options for any losses incentive there are several questions to consider:

1. For sub transmission (132, 66, 33, 25kV systems) then in general half hourly feeder demand measurements are already available via SCADA systems. Hence SM data is not specifically necessary to quantify losses on these systems however it is of note that SM data is generally more accurate than SCADA data. Are these systems therefore excluded from the losses incentive or should they have a separate mechanism? It is of note that these systems are responsible for approximately 40% of technical losses. If not given the existence of this data now, should any incentive focus on these networks in ED1 moving onto smart meter based methods in ED2?
2. Should the mechanism be based around a macro level (whole system) baseline losses value with a reward/penalty against this target value?
3. Should any losses incentive take into account (either by modelling or measurement) the whole system (including transmission assets) effects of initiatives?
4. Should the mechanism be based around a fixed MWhr incentive rate which can be applied against initiatives?
5. Should the mechanism be driven by measured or modelled changes in losses?
6. Should the mechanism be based on losses as a % of energy delivered or the absolute quantum of losses in MWhrs? If the latter how are changes in network demand accounted for.
7. How should activities such as DSR or other network optimisation initiatives be treated under the incentive. For example post fault DSR may result in an overall carbon benefit (technical losses versus embodied carbon savings) but will result in higher losses.
8. Should the incentive be based on carbon or MWhrs?
9. Should the incentive include / reward customer side of the meter initiatives such as energy reduction schemes? If so will the scheme be limited to DNOs? Or open to suppliers and other parties such as landlords?
10. Should the incentive be equal for non technical losses?
11. What is the customer's appetite for the rate and value of losses driven initiatives. In other words how much are they willing to pay on top of existing prices.

Are there any barriers and enablers to the above options that we need to start think about?

## Interaction with other incentives and obligations

A primary responsibility on DNOs is to operate an efficient network on behalf of customers.

At present any losses reduction efficiencies accrue to customers not DNOs and therefore any output based incentive regime on the DNO would need to incentivise the DNO to search for potential losses reduction initiatives and then to fund their resolution. The intervention funding could either be via an ex-ante allowance justified by the analysis or an ex-post allowance / reward based on delivered benefit / output or a combination of the two. In any event the sharing and pre-tax factors defined in the ED1 FD should be used to avoid perverse boundary issues.

Key to the losses debate is the definition of 'efficiency'. The Ofgem CBA tool provides an excellent reference point for undertaking such analysis. The cornerstone of this model is the energy price used for losses – system marginal price etc. The value assigned to this will need to be considered carefully particularly as the NPV of investments / operational initiatives to deliver losses reduction initiatives will be judged against this value.

Feedback from WS6 is this is the system marginal price and corresponding carbon intensity.

Having now established an agreed CBA model and having determine the methodology to be used from a) above, then an output measure could be defined in a number of ways.

- 1 Network analysis output. – The DNO could be required to report on the % of its LV and HV network (by feeder or length) that has been studied using the above data to ascertain if the CBA model would support intervention on losses. For example small section HV or LV feeders with high demands could be made larger or sub divided. These options can be evaluated via the CBA. The analysis output would allow stakeholders to see how active the DNO is in looking for such opportunities. It is important to note that the analysis may show the losses to be already optimised ie no further intervention viable under the CBA. This is a valid analysis outcome.

This is not considered necessary but places the risk of the cost of looking on DNO shareholders.

- 2 Intervention delivery – where the CBA supports intervention this measure could track the delivery rate of those initiatives, the unit cost and associated asset outputs. For example if the CBA showed that fitting a switched capacitor bank was the optimum solution and the CBA model showed this was viable then output 1 above would show the feeder had been analysed, and on delivery it would count an LV capacitor bank output. It would also count the losses reduction base on the analysis ie MWhrs.
- 3 An alternative count for both measures would be the % of customers fed from losses optimised networks.

Any mechanism would need to take into account the effect of incentives on customer bills and hence an expenditure or incentive cap may be needed to regulate the rate at which initiatives are implemented – ie over one or several price control periods as per WSC and UVA.

132 33 and 66kV networks already have scada data and therefore do not need SM data to undertake this analysis – a similar measure could therefore be formed for those networks – ie % analysed, % of identified interventions delivered, MWhrs saved, asset outputs and unit costs etc. These networks should definitely be included in the losses incentive as the energy losses are substantive.

Interventions can take many forms and its important the mechanism doesn't perversely incentivise certain approaches which could include general energy efficiency as in our stockport project, Smart Street approach, larger assets, losses reduction switching, meshing etc etc. It could also take the form of reduced or even subsidised connection costs for DG. Ie it may be that subsidised DG connection charges in certain areas of the network would result in lower losses for DUoS customers. Wjta would emerge quickly would be a table of intervention costs and their relative benefits.

The losses value in the CBA will change over time and hence provides an iterative approach to losses analysis – Ofgem could set this in its policy document every say 2 years to allow the mechanism to be made responsive to market price. Final thought as more LCT demand or DG is connected the network losses profile will change and hence there will be a periodic need to reassess losses interventions.

## Summary

In considering the potential of smart meters to help drive the efficient reduction of losses for customers, the group has identified a number of viable options. The relative merits of these options are dependant in part on the design of the incentive mechanism itself.

This paper identifies those questions that need to be considered to design the incentive mechanism itself. Given the specialist nature of incentive design, the group recommends that the ENA regulatory managers use this analysis to take forward the development of potential regulatory incentives for RIIIO-ED2.

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<sup>i</sup> Nominally 2% under the Measurement Instrument Directive