REDUCING DISTRIBUTION LOSSES BY DELAYING PEAK DOMESTIC DEMAND

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ABSTRACT

Since the resistive element of losses varies as the square of the current flow, times of high power demand make a disproportionately large contribution to network losses. A smoother demand profile over time would reduce losses, even without changing total demand. A spreadsheet model has been constructed to give a first approximation of the potential scale of distribution loss reduction from load-shifting by otherwise unrestricted domestic customers. The model combines network power flow and losses data with the consumption profiles of the domestic unrestricted customer class. The overall effect on distribution losses and its value are estimated – and appear relatively small.

REDUCING DISTRIBUTION LOSSES

An electricity distribution system loses a proportion of the electrical energy passing through it before that energy can be delivered to customers. A simple definition of losses is as the difference between units of electrical energy entering and units exiting (distributed by) the network.

Loss reduction strategies are opportunities to increase the efficiency of the electricity supply system and reduce its environmental impact. Distribution network operators (DNOs) in Great Britain are incentivised to reduce losses at a rate of approximately £50/MWh under the price control operating from 1st April 2005 to 31st April 2010 [1]. Some form of loss incentive is likely to continue beyond 2010.

Losses are necessarily calculated as the difference between two large numbers, and are thus volatile. Losses are also only *partially* under DNO control. However there are several potential ways for network operators to reduce losses, such as changes to the network design eg larger asset specification [2], operational schemes [3] and low-loss transformers [4]. Any alternative loss reduction strategies will always be of interest.

Loss reduction by demand profile change

Distribution losses are principally technical losses due to the physical flow of electricity through the network. They are composed of- fixed losses - principally from the iron losses in transformers independent of power flow - and variable resistive losses which vary as the square of the power flow [5, 6]. Thus electricity distribution at peak times disproportionately contributes to variable losses. Non-technical losses include theft and data errors such as systematic metering errors and this paper makes the simplifying assumption that non-technical losses are also relatively insensitive to total power demands and can thus be assumed to be part of the overall fixed losses.

In the context of a distribution network, R is the resistive component of the system impedance of a given network or network section. For an RMS value of current I varying over time t, the total resistive losses are,

$$\int I^2 R dt. \qquad (1)$$

Furthermore, since this current flow is associated with RMS power flow P at a distribution line voltage with RMS value V and a power factor $\cos\varphi$, the resistive losses are thus,

$$\int P^2 \frac{R}{\left(\sqrt{3}V\cos\phi\right)^2} dt. \qquad (2)$$

For any particular piece of network, there will be a constant factor of proportionality between the resistive losses and the integral over time of the power P squared ie

$$\text{resistive losses} \propto \int \left[P(t)\right]^2 dt, \text{ or } \propto \sum_t \left[P(t)\right]^2. \qquad (3)$$

Thus if the power flow at a given voltage level changes from P_A to P_B, the percentage change in resistive losses is

$$\frac{\int P_A^2 dt - \int P_B^2 dt}{\int P_A^2 dt}. \qquad (4)$$

Rationale for the investigation

If customer behaviour were modified to achieve smoother demand, in response to DNO/ supplier tariff incentives [7] and/or through automatic control of interruptible domestic loads, then losses could be reduced This would require the co-operation of consumers and other parts of the electricity industry eg metering, suppliers and appliance manufacturers. The investment required may be significant.

However the magnitude of this potential loss reduction effect is not obvious and has not been previously quantified. No quantitative mention of loss reduction by load management has been found in academic or industrial literature. For example a recent scoping study for demand side management for the UK electrical system did not

consider potential loss reductions [8].

Given the lack of indicative data, a new spreadsheet model has been created to analyse the impact on total distribution losses of modifying the shape of the demand profile for domestic unrestricted demand customers. This relatively homogeneous customer group contributes significantly to losses – accounting for 42% of electricity distributed but more than 56% of annual losses on the United Utilities network – and has significant resistive losses at peak periods. No new data have been collected for this work, but existing data from various sources have been combined.

The analysis in this paper does not examine the mechanism by which the profile shape could be modified, but instead investigates what the magnitude and value of the change might be for given profile shapes. Unless the value of the reduction is truly significant, it is not worthwhile to consider in detail what technical, regulatory and behavioural changes might be needed to cause the change in profile shape.

MODELLING APPROACH

In the model, power flow data series were set up at three generic voltage levels (EHV, HV and LV) for forty-eight half-hour periods t on each of fifteen representative days i. At EHV and HV the power data series are based on historical data on actual network power flows. At LV the power data series are based on the national consumption profiles used for electricity trading settlements. The fifteen days cover weekday, Saturday and Sunday for five 'seasons', with a weighting factor w_i to indicate how many times the profile occurs per year. Thus *at each given voltage level*, the percentage reduction in variable losses between P_A and P_B is given by,

$$\frac{\sum_i^{15} w_i \sum_t^{48} P_{Ait}^2 - \sum_i^{15} w_i \sum_t^{48} P_{Bit}^2}{\sum_i^{15} w_i \sum_t^{48} P_{Ait}^2}. \qquad (5)$$

In the model, the profile change amongst domestic unrestricted demand customers is entirely determined by two easily altered input variables. These are *the threshold proportion of the day's peak demand* and *the delay period*. For example, for every half-hour period with demand within a threshold say 15% of the maximum daily demand, demand is reduced by 15% of the maximum daily demand, and replaced after say 4 hours. Figure 1 shows an example of the square of the power demand in each half-hour ie a proxy for the variable losses for a 10% threshold and 8.5 hour delay on a winter weekday. The loss reduction at the peak evening period is larger than the early morning increase.
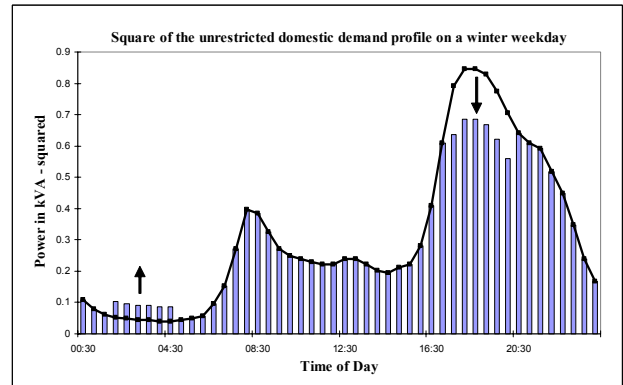

Figure 1. *Square* of the domestic unrestricted power demand for a winter weekday – before and after profile change with a 10% threshold and 8.5 hour delay.

On LV circuits dominated by domestic unrestricted customers, the overall power profile will have the same shape as the domestic unrestricted profile. At EHV and HV, the overall power profile is assumed to be a combination of the power flow to serve domestic unrestricted customers (which will be adapted by the load shifting) and a residual component serving other demand customers, including HV and EHV connected customers.

Losses on the United Utilities distribution network
The overall potential for loss reduction is a function of the existing losses level and of the profile shapes – for example with a more peaked profile there is greater scope for reduction in variable losses. Thus loss reduction potential is a feature of a given set of electricity demand patterns and will vary by geographical area and over time. A first approximation of the size of this effect has been made for the United Utilities distribution network, which supplies 2.2 million customers in the north west of England.

A loss adjustment factor (LAF) is a scaling factor between the units distributed to the customer (exiting the network) and the units entering the network (eg at a Grid Supply Point). Any LAF will refer to a given customer group and time period. To estimate loss adjustment factors for customer groups at different voltage levels, United Utilities runs a program 'LAF' developed for DNOs by EA Technology. The LAF program is based on approximate technical data for the United Utilities electricity distribution network. It then uses an iterative process which allocates the difference between units entering and exiting the network to fixed and variable losses at 16 different network levels in each half-hour period of the year [5].

If United Utilities meets the regulator's losses target in 2006/07, there will be approximately 1500 GWh of network losses associated with circuits with significant demand flows. Combining the output of the LAF model with billing data on the units distributed to the various different customer classes and a number of basic network

assumptions gives the allocation of losses shown in Table 1. The reductions in variable losses at each voltage level calculated from equation 5 are applied to the variable losses totals shown in bold.

Table 1. Estimate of demand-related losses at each voltage level and proportion associated with domestic unrestricted demand customers.

Voltage level	Losses in GWh			Associated with domestic unrestricted customers
	Fixed +	Variable =	Total	
EHV	105	**336**	441	42%
HV	75	**283**	358	44%
LV	229	**475**	703	71%
Total	409	1093	1502	

RESULTS

Table 2 shows the specific case of load shifting which delays 15% of the energy demanded by domestic unrestricted customers in peak periods by four hours. This is estimated to reduce total network losses by nearly 1 % or 13 GWh on the United Utilities network. This is equivalent to delaying nearly 5% of all the energy delivered to the domestic unrestricted customer class or 2% of the energy delivered to all customer classes. This would imply a reduction in associated (predominantly peak) generation costs to serve the network area of approximately £700k pa at a notional £50/MWh.

Table 2. Model results – for the United Utilities network

Profile change →		Top 15% by 4 hrs	Sensitivity case - flat profile
Energy delayed as proportion of total distributed	To domestic unrestricted customers	5.0%	16%
	To all customers	2.0%	6.5%
Reduction in variable losses		1.1%	5.4%
Reduction in total losses	% change	0.8%	4.0%
	Losses level (previously 5.68%)	5.63%	5.45%
	GWh/yr	13	64
	£ million/yr @ £50/MWh	0.7	3.2

Accuracy and sensitivity
It could already be deduced from the LAF model that losses to serve the same LV network customers in different half-hour periods can plausibly vary from 4-20% of units distributed. This might suggests some more significant

scope for loss reduction. However as only 56% of total fixed and variable losses are initially associated with the customer group, even a relatively dramatic profile change will not bring a dramatic loss reduction. The highest losses will occur only on specific days and times eg winter and autumn weekday evenings and weekend lunchtimes, while in contrast the net result is a weighted average across every half-hour of the year. Also in some cases when the delayed demand is replaced it is added to a relatively significant level of demand eg even the lowest level of demand on a winter weekday is comparable to the peak on a summer day. It must also be remembered that a significant proportion of variable losses also occurs at HV and EHV; the loss reduction is lower at these voltages because unrestricted domestic customers account for a smaller proportion of the total power flow and the residual power flow for other customer types does not coincide with the LV unrestricted profile. Finally variable losses only account for an estimated 74% of total distribution losses on the United Utilities network – the fixed losses are unaffected.

The small scale of reduction is broadly consistent with the scale of reduction found in a detailed study of the impact of distributed generation on network losses [9]. The dependence of losses on profile shape and customer location on the network is extremely complex. As such the model includes many approximations and assumptions and the results presented here are estimates of the potential scale of the loss reduction, rather than precise forecasts. Greater accuracy would updating of data inputs and require a much more detailed customer model including more half-hourly data on power flows – data not currently collected at LV.

As a sensitivity analysis, the limiting case of a flat demand profile was considered. On each of the 15 representative days the demand was uniform throughout the day at the mean power demand for that day. As shown in Table 2 above this gives a 4.0% reduction in total losses by shifting nearly 16% of domestic unrestricted demand or more than 6% of all units distributed to all customer types.

National implications of the results
If the United Utilities network is assumed to be representative of Great Britain and the results are scaled-up, the energy saved would be around 160 GWh per year, equivalent to the output of generation capacity of around 40 MW operating at 50% load factor annually. This does not however directly imply that this amount of generation could be retired.

The loss reduction would have a value of £8m pa in saved electricity costs at a notional generation cost of £50/MWh. 43% of the loss reduction would occur in winter (defined as 148 days with least daylight). This proportion is strongly dependent on the length of the delay period. This would imply avoided carbon emissions of nearly 29,000 tonnes per year. This is based on the average carbon emission factors

for coal and gas in the UK generation mix [10] together with the assumption that output from coal varies to meet peak demand in winter but gas in summer, deduced from [11]. If different assumptions were made about peak generators then the net carbon dioxide effect could be significantly different eg if a sustained profile change affects the use at peak of oil-fired plant, pumped hydro or imports. At a social cost of carbon of around £100/tC in 2006 prices, the additional value of the carbon reductions is around £3m per year. The social cost of carbon figure is based on the Stern review's estimate of $30/tCO2 in 2000 prices based on climate stabilisation at a 550ppm CO_2-equivalent atmospheric concentration [12].

Around 80% of domestic premises are on an unrestricted or single-rate meter and tariff ie approximately 20 million [13]. Thus the total £11m benefit deduced above equates to on average around 50p/year/household. Could that level of investment bring the desired demand response? That is difficult to answer without the context of a particular type of demand response, infrastructure cost and consumer effect. Experience to date of demand management in the UK and elsewhere is extremely limited, but as a first indication of scale the Italian programme to roll out 30 million smart meters had a unit cost of less than £50 [8]. Even if smart meters could facilitate the change in demand behaviour in the UK with no additional costs, the simple payback period of the avoided costs of losses against the meter cost on this basis might be 100 years. Crucially the costs and benefits do not accrue to the same actors in the energy system.

CONCLUSIONS

The modelling undertaken gives the first quantitative estimates of the scale of distribution loss reduction by domestic load shifting. The achievable scale of reduction seems small in comparison to the likely effort involved in achieving the profile change.

However the analysis so far may be overly conservative eg some energy demand may be avoided rather than replaced after a delay [8]. There are also other system benefits from load shifting; sustained load management also reduces transmission losses, the peak requirement for generation plant capacity, and transmission and distribution network capacity. The remaining generation plant is run at a higher load factor and generally a higher efficiency. Both private economic and social/environmental values may be assigned to each of these additional effects. The key test of whether domestic load shifting should be pursued is whether, once all the other potential costs and benefits have been considered, alternative carbon mitigation actions exist with a lower abatement cost.

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