
Title: **Options and proposed approach for Unmetered
Supplies charging within CDCM**

Synopsis: Report on behalf of DCMF Methodologies Issues Group -
Issues 12 & 21. The half hourly (HH) and non-half hourly
(NHH) CDCM tariffs sub-group.

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1. Introduction

1.1. Purpose

This document captures the main discussion points from the MIG sub-group meetings in February, March and April 2012 in respect of Distribution Use of System (DUoS) charges for Unmetered Supplies (UMS).

The MIG sub-group have built upon the work from the 2011 group by reviewing all the available options. Further analysis has been completed on the proposed approach. This has led the group to recommend a formal change to proceed under the DCUSA governance.

This document supports a DCUSA change proposal raised by the Methodologies Issues Group (MIG) in May 2012.

1.2. Background

Concerns were raised about the variances between non-half hourly (NHH) & half hourly (HH) traded UMS at the commencement of the Common Distribution Charges Methodology (CDCM) in 2010. This was raised and added to the log of potential changes. A group was formed in 2011 to discuss options for UMS charges ideally for implementation in April 2012. This group considered a series of 'ideas', eleven were documented in the final report dated 24 Jun 2011. Some of these 'ideas' challenged the fundamentals of the CDCM, which were also under debate in the metered market, it was agreed to form a new MIG sub-group to look at both issues together. This new group started meeting in the autumn of 2011, seeking to propose changes to be implemented in April 2013.

2. Existing UMS Arrangements

2.1. Summary of the UMS Issues

The BSC enables all unmetered customers to trade HH or NHH. Over recent years the proportion of UMS customers trading NHH has reduced. Some large UMS customers continue to trade NHH. These large customers may have demands in the order of 10MW with 50% load factor. Many continuous UMS customers continue to trade NHH as this has cheaper DUoS charges than the equivalent HH UMS DUoS charges. If the CDCM derived charges lead to a financial benefit to trade either NHH or HH, then the customers will migrate to the cheapest trading arrangement.

Settlements are more accurate where UMS customers trade HH as the consumption profile is more reflective than the NHH settlement profiles. UMS accounts for about 1.25% of settlement consumption, of which about two thirds is traded HH.

There is a wide range of customer groups with UMS equipment. The bulk of the consumption is street lighting load which is predominately dusk-dawn consumption. This profile dominates the CDCM model calculations, and an 'average customer' with this load profile may be charged appropriately. However, there are other significant customer groups which have different load profiles which are adversely impacted by the HH derived RAG process structures.

The current CDCM model attributes about two thirds of the revenue to be recovered from the HH UMS 'red' units. As the typical consumption in distribution areas for UMS is only during the four winter months then the total proportion of red units is low. This has the effect of calculating a high p/kWh for the red units. Any customer who has a pattern of usage which has a higher than 'average' red unit consumption (such as continuous communications equipment), incurs a disproportionately higher DUoS bill.

The DUoS revenue derived from customers trading HH or NHH should be equivalent as they have the same physical impact of the distribution system irrespective of how the energy is traded in settlement. Non-discrimination between customers is a key objective of the CDCM. Comparable charges will also reduce the incentive for customers to 'flip' from one trading arrangement to the other, which can lead to Distributors under-recovering forecast revenue. It also supports the desire to ensure that large energy customers trade on a HH basis to improve settlement accuracy.

The existing NHH trading arrangements already determine an EAC for each customer into four consumption categories, defined in BSCP520 (section 4.3)¹ as:

- A - Continuous
- B - Dusk to Dawn
- C - Half night and pre-dawn
- D - Dawn to Dusk

Each of these consumption categories is allocated into a defined SSC and associated TPRs, the EAC is allocated by a fixed percentage to each TPR. In the 2009/10 DUoS charging, pre-CDCM, some companies have charged different p/kWh for each of these unmetered consumption categories. Historically more companies had differentiated rates. The current CDCM approach calculates one rate for all the NHH profiles.

2.2. Impact of different DUoS Charges

UMS customers have the choice whether to trade under the NHH or HH arrangements. Using the current published DUoS charges the differences in charges becomes apparent for differing customer usage. The differences are incongruous when the customer consumption has an identical impact on the distribution network.

¹ www.elexon.co.uk/pages/bscps.aspx

Final charges for 2012/13 as published Feb 2012

	NHH Tariff	Profiles priced using HH DUoS Tariffs (average p/kWh)						
	p/kWh	typical profile	continous	part night		diff typical	diff cont	diff part night
NPG Yorkshire	1.861	1.789	2.718	2.992		-0.07	0.86	1.13
NPG Northern	2.088	1.952	2.957	3.152		-0.14	0.87	1.06
WPD East Mids	2.481	2.321	3.459	3.509		-0.16	0.98	1.03
WPD West Mids	2.500	2.392	3.510	3.534		-0.11	1.01	1.03
UKPN Eastern	1.759	1.617	2.094	2.288		-0.14	0.33	0.53
UKPN London	1.691	1.707	3.327	2.486		0.02	1.64	0.80
UKPN South East	2.032	1.785	2.425	2.652		-0.25	0.39	0.62
ENW	3.059	3.064	3.924	3.925		0.00	0.86	0.87
SP Dist	1.996	1.936	2.432	2.806		-0.06	0.44	0.81
SP Manweb	2.373	1.790	2.292	2.710		-0.58	-0.08	0.34
SSE South	2.478	1.853	2.840	2.815		-0.63	0.36	0.34
SSE Hydro	4.335	4.205	5.913	5.791		-0.13	1.58	1.46
WPD South Wales	3.561	3.261	4.062	4.883		-0.30	0.50	1.32
WPD South West	3.214	3.274	3.927	4.850		0.06	0.71	1.64

The above table shows the published NHH single rate and then the average p/kWh using the HH RAG prices, for a customer with: 'typical' dusk-dawn load, a fully continuous load and a part-night load. In each case HH data has been created to reflect the customer consumption profile, which has then been used to derive the annual DUoS charge presented as an average p/kWh.

As can be seen the 'typical' customer trading HH, has similar average prices to the NHH single rate.

The red, amber, green (RAG) average rate derived for a continuous customer are noticeably higher because the continuous load hits all the red periods throughout the year, yet the derived red p/kWh is artificially high from the relatively small number of units attributed to red by the 'average' HH UMS customer – which only uses red units during the winter months. The continuous customer is therefore significantly over charged if trading HH. The part night customer is also charged more than the average NHH rate, but this is probably, to an extent, appropriate as they are not using cheap 'green' units from midnight to 05:00 which would otherwise reduce the average unit rate.

2.3. CDCM model assumptions

The assumptions, and input data, in the CDCM model are fundamental to the CDCM calculation.

Appendix 1 shows the HH & NHH consumption in each distribution area. For some areas the remaining NHH UMS is predominantly continuous load. For one of the areas, when the NHH load factor is recalculated, using the NHH UMS consumption in the four categories, the average NHH load factor becomes 0.67. Where this is entered into the CDCM model to replace the common HH UMS value, a different tariff is calculated, noticeably reducing the single NHH UMS price. So much so, that HH customers would find it advantageous to move to NHH.

This interaction between of the different CDCM charging principles for NHH & HH could have the effect of distorting the market. The impact is most evident in the UMS market, but a similar effect is undoubtedly occurring in the metered market.

2.4. Other Considerations

2.4.1. De-linking

A radical approach would be to determine DUoS charging based on the total units used at each voltage level, almost irrespective of the customer type using the energy. This would determine a RAG charge at HV, substation fed and LV network. It does not matter to Distributors' which end customer used the electricity, so the HH data from settlement would be used to charge the suppliers based on the aggregated consumption at each voltage level. The Supplier can then set their customer retail charges including the appropriate proportions of each time category, based on settlement NHH data or HH data as they determine. The appropriate recovery of service charges, and some elements make the approach more complex than described above. This approach is being considered further by the MIG sub-group to assist resolution of difference between metered customers.

2.4.2. Level of red charges

Two thirds of UMS revenue is attributed to the red units. This is particularly high in UMS (compared with metered customers) due to the typical pattern of consumption of this customer group. A different MIG sub-group is considering whether more of this revenue should be recovered through amber or green units. This work is happening in parallel with this UMS proposal, but is expected to be entirely compatible.

3. Options under consideration

Four options were discussed at the meetings in February & March 2012:

- Use the NHH UMS derived single price and apply to HH UMS
- Determine NHH UMS prices for the four categories, and a Seasonal Time of Day HH charge structure
- Split HH UMS into four different categories, and determine four UMS charges applicable to NHH & HH
- Determine a capacity based UMS charge approach for NHH & HH customers

These are all discussed in further detail below.

3.1. Single rate UMS DUoS charge

3.1.1. Proposal

Use the NHH derived single rate UMS p/kWh across both NHH & HH traded customers.

3.1.2. Impact on CDCM model

No model software changes.

Input data change – take all (NHH & HH) UMS consumption and enter into the NHH UMS row on the input table.

All the revenue is calculated as if NHH UMS.

If zero HH UMS consumption is entered in the current model, the model still calculates a RAG p/kWh in the tariff tab for HH UMS, using some default criteria. Although as the HH UMS consumption is zero this is not used in the overall revenue calculation.

3.1.3. Customer Impact

It is simple.

It is non-discriminatory across NHH & HH settlement trading arrangements.

Enables energy saving initiatives such as “switch off” or “dimming” in the night-time period (typically between midnight and 6am) to benefit at the ‘average’ NHH UMS rate, rather than the ‘green’ rate in the HH tariff. The impact of this can be illustrated by an example. A street lighting authority with non half hourly settlement that switches from a dusk-to-dawn operation pattern (category B) to a half-night operation pattern (category C) would reduce its total consumption by about a half, but would not reduce its contribution to the load on the DNO system at the time of system peak. If a single tariff is used for all non half hourly unmetered supplies, then that authority would reduce its use of system charges by about a half, without giving any commensurate savings to the DNO. By contrast, if separate tariffs apply to category B and C, then the reduction in the number of units would be offset by the higher unit rate applicable to category C than category B, and therefore the charges would better reflect distribution network costs.

3.1.4. Industry Impact

Loss of the RAG cost reflectivity signals, although the majority of UMS customers are unable to respond to these cost signals. The winter early evening is when most street lighting is required.

UMS customers making energy saving initiatives that reduce consumption during night time period gain the benefit of saving the ‘average’ NHH UMS rate.

This approach as a resolution for UMS, has no comparable resolution impact for metered customers.

3.1.5. Comment

Results in loss of cost reflectivity through the removal of time of use charges.

Will result in identical NHH & HH charges for all UMS customers.

It will overcharge, or undercharge, some customer profiles.

This approach is simple, the group believe this option could be implemented in April 2013.

Not recommended to be considered further.

3.2. NHH UMS four category prices, and a seasonal HH charge structure

3.2.1. Proposal

Modify the NHH UMS structure to determine a different charge for each of the existing four BSC categories:

- A - Continuous
- B - Dusk to Dawn
- C - Half night and pre-dawn
- D - Dawn to Dusk

And, determine a seasonal RAG charge structure for the HH UMS customers using the similar logic as for EHV customers. Three bands defined as (these times/dates differ across the country):

- 'Super Red' - same as EHV charging (see section 2.22 of each Distributors published charging statements)
- 'Yellow' as existing red & amber, less the 'Super Red'
- Green as existing, equal to the remainder of time, less 'Super Red' & 'Yellow'

3.2.2. Impact on CDCM model

Enter the NHH UMS by their four different consumption categories. Calculation method should be same as HH to ensure a customer with same NHH profile and HH charging would incur same charges.

Modify the HH UMS charges to calculate a 'super red' charge during the times/dates defined by the Distribution business as their 'peak consumption'. The 'peaks' are generally on weekday evenings during the four winter months, however there are exceptions, such as London which has a peak during the day in the summer due to the significant air conditioning load. During the remainder of the year the 'yellow' and 'green' charges would be determined based on rules.

NHH charges would be determined based on proportion of super red, yellow and green in each NHH category. Each NHH category would therefore incur a different p/kWh.

See later section for more detail.

3.2.3. Customer Impact

The current single rate NHH UMS rate averages the four different patterns of usage and determines 'an average'. The average rate is typically thought to be too low for part night usage.

"Typical HH customers" would be charged similar to now. Atypical HH customers with additional red consumption (typically continuous load) at other times of the year would not be adversely impacted.

Customers would need to understand the different, more cost reflective charges.

3.2.4. Industry Impact

Four rates would be derived for all the NHH UMS. These are currently separately identified and each customer has a separate UMS MPANs for each category. Distributors have generally retained separate LLFC for each of these consumption categories. DUoS rates would differ for each category so DUoS and Supplier billing would reflect these differences. Parties should not require system changes, only configuration changes for different p/kWh charges for each of the NHH categories.

The HH customers already have HH data, this would be charged based on the different tariffs through the year. Some Suppliers & Distributors may have adopted a 'spread sheet approach' for DUoS billing of the relatively small number of EHV customers in their portfolio. Therefore charging HH UMS customers on this proposed basis may require some billing system changes. However, the approach will vary depending on the numbers of customers in the respective portfolio. Appendix 1 indicates the numbers of HH UMS customers, which, in total may be smaller than the number of EHV customers.

3.2.5. Comment

Retains cost reflectivity through the continued use of time of use charges.

Results in comparable NHH & HH charges for customers with similar load profiles.

The group believe this option could be implemented in April 2013.

Recommended to be considered further – see later section.

3.3. Split HH UMS into four different categories, determine four UMS charges

3.3.1. Proposal

Currently all HH UMS consumption is combined into a single MPAN, with consumption profile determined by characteristics of the equipment being used. So the proposal is to split HH UMS consumption into four different categories (categories are same as existing NHH categories), each with their own MPAN. Determine a different chargeable p/kWh for each of the four categories

3.3.2. Impact on CDCM model

Create four UMS tariffs for each of the current NHH categories. Each would have total input data combined from the NHH & HH usage in that category.

Then determine four UMS charges applicable to both NHH & HH. Would need to decide whether to use the NHH or the HH pricing method in CDCM.

The charges calculated would determine four different single rate charges, one for each category. The single rate charges would be applied to all NHH & HH units used in that category.

3.3.3. Customer Impact

Added complication for existing HH customers who would change from one MPAN to four MPANs.

Expectation of increased charges from supplier (standing charges) and from agents for multiple MPANs.

Charges for NHH & HH are identical in each category.

Could lead to differing approaches for which type of load is attributed to which for the four NHH consumption categories. Significantly different DUoS charges will encourage debate and challenge to which category each type of load is attributed. Customers would argue that their equipment should be included in the category with the cheapest p/kWh.

Complications come for CMS controlled street lighting which may default to dusk-dawn, but may be being actively controlled to be a part night regime. Although if it dims at night is that still dusk-dawn or part night? How much dimming triggers a change from part night to dusk-dawn.

Where CMS controlled equipment is in use, it may result in further MPANs, and a requirement to further split the inventory into the four categories.

3.3.4. Industry Impact

Added complication for UMSO to split the customer inventory into the four consumption categories to create four summary inventories to submit to the Meter Administrator.

Meter Administrator to calculate 4 MPANs where currently calculating one.

HHDC, HHDA, Distributor and Supplier all need to manage invoicing consumption split over 4 MPANs rather than the current combined single MPAN.

Reduction in the cost reflectivity from RAG.

3.3.5. Comment

Complicated and requires operational changes, will add direct costs for customers to assist 'industry' to resolve unequal DUoS charging derived in CDCM.

Results in comparable average NHH & HH charges for customers with similar load profiles.

The group believe this option could be implemented in April 2013.

Not recommended to be considered further.

3.4. Capacity based UMS charge approach for NHH & HH customers

3.4.1. Proposal

Determine a capacity based charging regime – not based on units consumed.

3.4.2. Impact on CDCM model

Amend to determine a £/kW of capacity (effectively kW maximum demand) for HH and NHH UMS. This introduces a 'third' charging philosophy into the CDCM model.

The NHH EAC and associated profiles are effectively fixed in settlement; therefore the load factor is pre-determined for each of the four consumption categories. This enables 'reverse engineering' to determine p/kWh which are equivalent to a capacity charge. This avoids the need to introduce a new data item into billing derived by the UMSO from the submitted inventory.

Consideration would need to be given to the NHH category 'dawn-dusk' which has small consumption, but avoids most of the 'red' times, except in London and North Scotland areas which have red times during the weekday daylight hours.

3.4.3. Customer Impact

Customers would incur a charge dependent on their demand on the network. A customer would incur a fixed charge each month. A customer, with say continuous load which has the same maximum demand, would incur that same charge, although they have used approximately twice the kWh in the month.

'Average' customer	47% load factor	charge £x/year	average [y (=baseline)] p/kWh
Continuous customer	100% load factor	charge £x/year	average [47/100 = 0.47y] p/kWh
Part night customer	27% load factor	charge £x/year	average [47/27 = 1.74y] p/kWh

Each customer has different consumption profile, but same total demand. So each customer pays the same total charge for DUoS per year, but the continuous customer pays approximately half the average p/kWh compared with the 'average' customer. The part night customer uses the fewest units, and therefore pays some 74% over the 'average' unit price.

A customer moving from dusk-dawn lighting regime to a part night lighting regime would continue to pay the same each month in DUoS revenue. By turning street lights off for 5 hours per night there is no reduction in DUoS charges, despite reducing the units distributed. The reduced consumption would effectively be charged at a higher p/kWh to recover the same revenue.

Customers would be incentivised to apply changes to inventory on the 1st of the month. Any changes mid-month would result in the higher charge applying for the whole of the calendar month.

3.4.4. Industry Impact

Amend HH DUoS billing to change based on capacity charge in the relevant month. Using HH data the capacity charge would increase to a value equivalent to the maximum demand in the month. This would reset in the following month allowing for minor changes month-month based on inventory changes, and where CMS controlled lighting has affected the MD. The monthly fee will remain broadly consistent throughout the year as at some time in the day (for 365 days) the maximum consumption will be the same.

If the Distribution costs are wholly determined by peak demand then this charging approach is correct. Albeit it is difficult for stakeholders to relate to. Some customers may regard it negatively, as they seek to save energy through part-night lighting, they are then charged the same DUoS revenue whether the load is continuous, dusk-dawn or part night.

This change is somewhat radical, and will require full explanation.

Loss of time of day cost reflection. An unmetered load used at 5-6pm each day pays the same as one at 2-3am, although cannot identify a 'real' example where this may be relevant.

3.4.5. Comment

This change is radical and will need careful explanation across stakeholders. A sensitivity analysis of existing customers would be appropriate.

Not recommended to be considered further.

4. Proposed approach

At the meeting on the 9th March & 27th April 2012 the group agreed to propose the option describe above in section 3.2. This has been further expanded with an example.

4.1. Methodology

Modify the CDCM pricing model as follows. This will be further refined during the CP process:

- 1 Enter forecast consumption data as:
 - a. HH UMS in proportion of RAG and/or Super Red/Yellow/Green
 - b. NHH UMS in each of the four NHH consumption categories
 - c. Percentages of each NHH consumption category to be attributed to each DUoS time band
 - d. Total (NHH + HH) UMS co-incidence and load factor
- 2 Define UMS time bands as:
 - a. 'Super Red' time in same way as EHV charging (see section 2.22 of each published charging statement)
 - b. 'Yellow' equal to be remainder of time less 'Super Red' & 'Green'
 - c. Green as existing
- 3 The model will use:
 - a. NHH UMS energy from each of the four consumption categories (1b) added to the energy in the three HH UMS DUoS consumption bands (1a) using the "BSC standard profile" percentages in each defined times/profile (1c)
 - b. the total (NHH + HH) UMS energy in each of the three DUoS time bands is used to determine HH UMS prices for that band
 - c. the HH UMS prices will determine a single rate price for each of the four NHH UMS categories, using the same percentages of proportion of consumption in each of the time bands (1c)

4.2. Data inputs

To make the CDCM model work in the revised manner the following forecast information is required:

- 1 HH UMS consumption (MWh) split into three DUoS time bands (*existing*)

This should be available from historic consumption data in the respective distribution area

- 2 NHH UMS consumption (MWh) split into the four NHH categories (*new*)

This may be available from internal Distribution company data sources, using SSC or LLFC splits, or from Elexon (see Appendix A).

- 3 Percentage split of NHH consumption into the three time bands (*new*)

Standard industry profile data is used to derive the settlement data. NHH settlement data is adjusted for temperature in the GSP Group, but not daylight hours. It therefore varies slightly across the country. Elexon have provided typical data which could be used to determine some national factors. The group considering the CP will need to consider whether a single set of values can be used nationally, or whether individual GSP Group data should be used. Whichever profile is used the split in the three time bands will differ based on the Distributors definition of the three DUoS time bands.

The significance of the two approaches should be considered in context of transparency, simplicity, materiality, UMS is 1.25% of settlement and NHH is, on average only a third of that.

- 4 Coincidence & load factors (*revised*)

These will need to be set appropriately to reflect the total UMS profile. Need to revisit the approach in the CP stage.

4.3. Example

An example of the methodology was created. UKPN EPN was selected, partly as the UMS has been fairly stable over the last few years, and the area is generally regarded as fairly 'average'. Further details are shown in Appendix 2. Together with some further explanation. The associated spread sheet is also available.

The conclusion is that introduction of super red prices increased, but not massively, the p/kWh during the peak time band. The NHH UMS prices for each category changed in line with expectation.

Two sources of new information are required as input data as described in Data Inputs, above.

4.4. Further work

There is further work required during the CP stage, it is proposed to include:

- 1 Define the changes required to the CDCM model
- 2 Define the source and considerations of the forecast input data
- 3 Prepare calculations for all distribution areas to ensure no unintended consequences, or extreme prices are calculated. Particularly with the other extremes, such as Hydro with high proportion of red time, Northern with low proportion of HH UMS, London with daytime summer super red times.
- 4 Consider the impact on a range of customers to ensure no unintended consequences
- 5 Consider the impact of the other potential CDCM changes, such as recovering certain costs through the yellow/green charges, rather than super red. This is expected to be beneficial, but that should be verified (see 7)
- 6 Review the methods to determine coincident and load factors
- 7 Consider whether some of the 'revenue matching' adjustment should also be recovered through yellow or green units, rather than all in super red. If so, determine a set of rules for this adjustment (see 5)
- 8 Some Distributors may need to recreate LLFC to split the NHH UMS into the four categories, to enable billing from April 2013.
- 9 Ensure that the BSC arrangements are clearer on the attribution of UMS equipment to the appropriate NHH categories, to prevent gaming and ensure consistent national approach

Appendix 1 – Elexon sourced UMS data

This is base data obtained by PDA from ELEXON. The NHH UMS (middle table) changed in some areas in April 2011 by the volumes transferred to HH shown in the bottom table.

UMS Consumption directly from ELEXON for April 2010 to March 2011										
sp_group	GSP name	HH Energy (MWh)	NHH Energy (MWh)	HH UMS MSIDs	NHH UMS MSIDs	HH Energy/total	total UMS energy			
A	Eastern	316,406	99,773	57	3,772	76%	416,179			
B	East Midlands	307,989	82,935	15	2,473	79%	390,924			
C	London	109,269	161,807	22	572	40%	271,076			
D	Manweb	48,383	167,927	9	722	22%	216,310			
E	Midlands	249,881	112,797	16	1,656	69%	362,678			
F	Northern	4,329	275,337	2	1,396	2%	279,667			
G	North West	304,760	50,005	25	678	86%	354,765			
H	Southern	262,950	77,946	29	3,501	77%	340,896			
J	South East	186,625	65,269	17	1,392	74%	251,894			
K	South Wales	153,067	16,467	20	1,281	90%	169,533			
L	South West	155,704	25,072	15	1,453	86%	180,776			
M	Yorkshire	209,143	113,417	11	964	65%	322,560			
N	South Scotland	19,736	416,416	1	5,050	5%	436,152			
P	Scottish Hydro	16,940	113,748	2	6,269	13%	130,688			
	totals	2,345,184	1,778,914	240	31,178	57%	4,124,098			
UMS data - latest run 1 April 2010 - 31 March 2011										
MPAN counts are MPAN days divided by 365.										
UMS NHH Consumption annualised from settlement run on 13 Mar 2011										
sp_group	GSP name	Cat A - Continuous	Cat B - Dusk-dawn	Cat C - Part night	Cat D - Dawn-dusk	NHH Energy (MWh)	Cat A - Continuous	Cat B - Dusk-dawn	Cat C - Part night	Cat D - dawn-dusk
A	Eastern	67,068	27,796	616	2,698	98,178.11	68%	28%	1%	3%
B	East Midlands	51,016	23,607	259	9,876	84,757.23	60%	28%	0%	12%
C	London	59,197	91,640	488	8,934	160,258.34	37%	57%	0%	6%
D	Manweb	33,771	130,241	634	0	164,646.34	21%	79%	0%	0%
E	Midlands	67,536	36,297	546	6,671	111,050.87	61%	33%	0%	6%
F	Northern	45,091	227,116	573	1,571	274,350.52	16%	83%	0%	1%
G	North West	32,310	17,029	1	0	49,340.94	65%	35%	0%	0%
H	Southern	46,239	30,536	1,163	3	77,940.67	59%	39%	1%	0%
J	South East	37,268	24,057	1,206	2,994	65,525.30	57%	37%	2%	5%
K	South Wales	8,558	6,549	450	0	15,557.05	55%	42%	3%	0%
L	South West	17,711	6,172	648	0	24,530.88	72%	25%	3%	0%
M	Yorkshire	38,487	73,117	715	0	112,319.08	34%	65%	1%	0%
N	South Scotland	92,169	308,397	2,364	0	402,929.59	23%	77%	1%	0%
P	Scottish Hydro	14,645	92,282	855	70	107,851.45	14%	86%	1%	0%
	totals	611,066	1,094,835	10,518	32,816	1,749,236.36	35%	63%	1%	2%
UMS data - annualised energy as at SF Run for 13/03/2011										
Note that continuous load is predominate in the GSP Groups which have most large customers traded HH										
UMS Consumption from ELEXON for April 2010 to March 2011, with PDA estimate of changes in April 2011										
sp_group	GSP name	HH Energy	New HH from 2011	NHH Energy	HH UMS MSIDs	NHH UMS MSIDs	HH Energy/total	total UMS energy		
A	Eastern	316,406	9,217	90,556	57	3,772	78%	416,179		
B	East Midlands	307,989		82,935	15	2,473	79%	390,924		
C	London	109,269	36,065	125,742	22	572	54%	271,076		
D	Manweb	48,383	39,156	128,771	9	722	40%	216,310		
E	Midlands	249,881		112,797	16	1,656	69%	362,678		
F	Northern	4,329		275,337	2	1,396	2%	279,667		
G	North West	304,760		50,005	25	678	86%	354,765		
H	Southern	262,950	6,553	71,393	29	3,501	79%	340,896		
J	South East	186,625	7,039	58,230	17	1,392	77%	251,894		
K	South Wales	153,067		16,467	20	1,281	90%	169,533		
L	South West	155,704		25,072	15	1,453	86%	180,776		
M	Yorkshire	209,143		113,417	11	964	65%	322,560		
N	South Scotland	19,736	143,862	272,554	1	5,050	38%	436,152		
P	North Scotland	16,940	86,017	27,731	2	6,269	79%	130,688		
	totals	2,345,184	327,909	1,451,005	240	31,178	65%	4,124,098		
			2,673,093							
UMS data - latest run 1 April 2010 - 31 March 2011										
MPAN counts are MPAN days divided by 365.										

Appendix 2 – UKPN EPN Example

The published UKPN (EPN) CDCM model has the forecast UMS consumption data. The NHH UMS was proportioned into the three DUoS time bands, using the splits shown on the second sheet. The revised UMS data (same total UMS volume), was re-entered in the model as HH UMS data, with NHH set to zero.

Information taken from UKPN EPN published spreadsheet				
	Rate 1 units (MWh)	Rate 2 units (MWh)	Rate 3 units (MWh)	MPANs
> NHH UMS				
NHH UMS	96,427.937			3,778
LDNO LV: NHH UMS	28.971			18
LDNO HV: NHH UMS	181.909			86
> LV UMS (Pseudo HH Metered)				
LV UMS (Pseudo HH Metered)	22,442.148	79,781.718	212,099.871	60
LDNO LV: LV UMS (Pseudo HH Metered)	.	.	.	
LDNO HV: LV UMS (Pseudo HH Metered)	.	.	.	
<div style="text-align: center;">↓</div>				
NHH splits. Used to apportion the NHH EAC to the HH RAG	8%	34%	58%	
Revised				
> LV UMS (Pseudo HH Metered)				
LV UMS (Pseudo HH Metered)	30,055.659	112,977.864	267,718.151	
LDNO LV: LV UMS (Pseudo HH Metered)	2.287	9.973	16.710	
LDNO HV: LV UMS (Pseudo HH Metered)	14.363	62.624	104.922	
EPN split of NHH units - derived from NHH data from Elexon. Used to ratio the CDCM model NHH EAC				
NHH UMS Cat A - cont	67,068	68%		
NHH UMS Cat B - dusk-dawn	27,796	28%		
NHH UMS Cat C - part nt	616	1%		
NHH UMS Cat D - dawn-dusk	2,698	3%		

The 2010/11 data from Elexon give the split of NHH UMS across the four UMS Categories. The total recorded volume is different from the UKPN 2012/13 forecast, but the proportions are assumed to be the same. These proportions have been used to allocate the 2012/13 forecast NHH UMS across the four categories. The majority of UKPN EPN UMS is traded HH, the residual NHH is largely continuous load (see Appendix 1 for other areas).

The second sheet is shown on the following page. The top of the sheet shows the split of NHH UMS into the four NHH categories. The split of the NHH total into the RAG DUoS time bands is determined from research data, the split for continuous load is effectively the annual hours in each time band, the dusk to dawn is based on typical customer data, etc. Similar split was performed for the super red, yellow, green table. These percentages are reasonably accurate, but will be refined (may change a per cent or so) during the CP stage.

The total UMS consumption was re-entered into the CDCM model which determined the slightly different RAG p/kWh. Difference presumed to be the difference between all energy being treated as HH, and the model not calculating anything as NHH. The CDCM determined revenue is what is expected as the revenue contribution from UMS. The remaining calculations are all about how to set the charges.

The methodology shown here, sets the super red p/kWh rate to ensure the same revenue is achieved from the reallocated (red to yellow) units and the arbitrary rule that green p/kWh remains the same, and the yellow p/kWh = amber p/kWh.

The chargeable NHH p/kWh set as the average rate based on their contribution of super red, yellow and green units. The NHH p/kWh differs across the four categories in the manner anticipated.

Example for UKPN (Eastern)									
	EAC (MWh)	Red	Amber	Green	Red (MWh)	Amber (MWh)	Green (MWh)		
NHH UMS Cat A - cont	66,017	9%	39%	52%	5,901	25,570	34,546		
NHH UMS Cat B - dusk-dawn	27,360	6%	21%	73%	1,642	5,746	19,973		
NHH UMS Cat C - part nt	606	10%	36%	53%	62	221	323		
NHH UMS Cat D - dawn-dusk	2,656	1%	65%	34%	25	1,732	898		
HH UMS	314,324	7%	25%	67%	22,442	79,782	212,100		
					total	30,072	113,050	267,840	65%
						7%	28%		
Using the RAG HH data for all UMS entered into 2012/13 CDCM model to derive new RAG charges									
					Red	Amber	Green		
					15,178	0.873	0.685		
All units had been charged at HH RAG charges - then revenue =									
					£ 4,564,375	£ 986,931	£ 1,834,703	£ 7,386,008	This is same as determined UMS revenue in CDCM model
Reallocate UMS kWh to super red, yellow and green times									
	EAC (MWh)	Super Red	Yellow	Green	Super Red	Yellow	Green		
NHH UMS Cat A - cont	66,017	3%	45%	52%	1,922	29,549	34,546		
NHH UMS Cat B - dusk-dawn	27,360	5%	22%	73%	1,368	6,019	19,973		
NHH UMS Cat C - part nt	606	9%	38%	53%	53	230	323		
NHH UMS Cat D - dawn-dusk	2,656	1%	65%	34%	25	1,732	898		
HH UMS	314,324	6%	26%	67%	19,299	82,925	212,100		
					total	22,667	120,455	267,840	65%
						6%	29%		
Post CP CDCM determined prices (p/kWh)									
	p/kWh	Super Red	Yellow	Green	Super Red	Yellow	Green		
NHH UMS Cat A - cont	1.327				19,851	0.873	0.685		
NHH UMS Cat B - dusk-dawn	1.685								
NHH UMS Cat C - part nt	2.438								
NHH UMS Cat D - dawn-dusk	0.991								
HH UMS	1.911								
weighted average NHH	1.426								
Compare with 2012/13 revenue									
	EAC (MWh)	NHH (p/kWh)	2012/13 DUoS Revenue	total	Anticipated DUoS Revenue	total			
NHH UMS Cat A - cont	66,017	1.759	£1,161,231	£1,161,231	£ 381,483	£ 257,964	£ 236,638	£ 876,085	-25%
NHH UMS Cat B - dusk-dawn	27,360	1.759	£ 481,266	£ 481,266	£ 271,567	£ 52,548	£ 136,815	£ 460,929	-4%
NHH UMS Cat C - part nt	606	1.759	£ 10,666	£ 10,666	£ 10,563	£ 2,011	£ 2,211	£ 14,785	39%
NHH UMS Cat D - dawn-dusk	2,656	1.759	£ 46,714	£ 46,714	£ 5,054	£ 15,118	£ 6,155	£ 26,326	-44%
HH UMS	314,324	1.801	£ 3,488,632	£ 3,488,632	£ 3,831,063	£ 723,935	£ 1,452,884	£ 6,007,882	6%
								£ 7,386,008	0.333%
Overall revenue increases slightly due to all UMS being calculated using HH method in CDCM? Or just rounding?									
					Red	Amber	Green		
					15,545	0.884	0.692		
NHH relative charges vary as anticipated									
HH revenues increase to compensate for reduced NHH CDCM revenue. NHH revenue reduced as p/kWh reduce									