

### DCUSA DCP 130 Consultation Responses – Collated Comments

<b>Question One</b>	<b>Do you understand the intent of the CP?</b>	<b>Working Group Comments</b>
British Gas	Yes	Noted
Electricity North West	Yes	Noted
Franck Latrémolière (speaking for himself only)	Yes	Noted
Northern Powergrid	Yes	Noted
Power Data Associates Ltd	Yes	Noted
ScottishPower Energy Retail	Yes	Noted
SmartestEnergy	Yes	Noted
SP Distribution and SP Manweb	Yes	Noted
SSE Supply	Yes	Noted
SSEPD SHEPD	Yes	Noted
UK Power Networks	Yes	Noted
Western Power Distribution	Yes	Noted
<b>Question Two</b>	<b>Are you supportive of the principles of the CP?</b>	<b>Working Group Comments</b>
British Gas	To the extent that it aims to produce more cost reflective tariffs to reflect the different categories and seasonality of UMS, we are supportive of the principles of the CP. However we do not agree with the proposal to implement option 2 for the setting of UMS coincidence factors. We believe option 2 is flawed.	The Working Group noted that coincidence factors will be addressed under question 5.
Electricity North West	Yes	Noted
Franck Latrémolière	The “principles of the CP” are not defined in the change proposal or the	The Working Group noted that the respondent was

(speaking for himself only)	consultation document. Whilst I have sympathy for the changes proposed, I do not support the intent as drafted. This is because the change proposal tries to do several disparate things, rather than defining a single achievable target (like remedying an identified defect). Points 1–3 in the intent are expressed in terms of means rather than ends. Point 4 is expressed as an end with no means. As far as I can tell, the objective of point 4 does not actually require the means of points 1–3. In particular, consistency between pseudo half hourly and non half hourly tariffs would be achieved under the current proposals even if the black time band was not seasonal, or even if black was the same as red. I think that the rationale for moving to seasonal time bands for unmetered tariffs is to prevent excessive coincidence correction factors for unmetered tariffs; but preventing charges based on such excessive factors is not explicitly part of the intent.	suggesting that the CP was doing several things at once. It was noted that the intent of the Change Proposal cannot be amended.
Northern Powergrid	Yes.	Noted
Power Data Associates Ltd	Yes	Noted
ScottishPower Energy Retail	We are broadly supportive of the change. We believe this will improve the cost reflectivity of UMS charges although are unsure whether this will no longer incentivise HH customers to elect to settle on a NHH basis as intended.	The Working Group noted that the respondent agrees that the CP will make charges cost reflective but that they are unsure whether it will stop customers moving from HH to NHH.  It was agreed that the Change Report should note that DCP 130 seeks only to look at Distribution Use of System charges and cannot impact on other factors that could encourage customers to choose to move between HH/NHH settlement.
SmartestEnergy	Yes. We are not entirely comfortable supporting a proposal which incentivises NHH meters to go to HH <u>AND vice versa</u> . This is generally not in keeping with industry attempts to use half hourly data increasingly. However, we agree with the view that the benefit/disbenefit of NHH vs HH is a settlement question and not a UoS charging objective. Also, deliberately making NHH charges more expensive where there is no cost reflective basis for doing so wouldn't be allowed.	See above comment

SP Distribution and SP Manweb	Yes	Noted
SSE Supply	Yes.	Noted
SSEPD SHEPD	Yes	Noted
UK Power Networks	Yes	Noted
Western Power Distribution	Yes	Noted
<b>Question Three</b>	<b>Do you consider that the proposal better facilitates the DCUSA Objectives? Please provide supporting information.</b>	
British Gas	<p>We do not agree with the working group's preference for option 2 in calculating coincidence factors for UMS. The purpose of the 3 year average approach for coincidence factors (and load factors and proportion of units in time bands) is to smooth out changes over time of a data set calculated on a consistent basis, not to smooth out fundamental changes to the basis on which the data items are calculated. We therefore do not think that the solution as proposed better meets the CDCM objectives because of this flaw. On the basis that the correct option for coincidence factors is implemented instead (option 1) we provide the following views on the facilitation of DCUSA objectives.</p> <ol style="list-style-type: none"> <li>1. We agree with the working group that the change proposal better meets CDCM objective one by reducing the differential between the tariffs and encouraging customers and suppliers to choose the appropriate settlement approach.</li> <li>2. Potentially, we agree with the working group that the change proposal better meets CDCM objective two by reducing the differential in use of system charges between the tariff groups and increasing the cost reflectivity of prices. However, we also believe that there is a potential negative impact on competition due to the scale of change applying to individual UMS tariffs and the short timescales of the notice of the impact of this change.</li> <li>3. The working group states that the change proposal better meets CDCM</li> </ol>	<p>The Working Group agreed that the first comment, regarding coincidence factors, should be addressed under question 5.</p> <p>It was noted that the CP sought to prevent customers from gaming by removing the difference between HH and NHH DUoS tariffs. The Working Group noted that point three of British Gas's response did not take this into consideration. The group clarified this point with British Gas and it was agreed that the Change Report should clarify that CDCM Objective three is better facilitated by reducing the differential between tariffs.</p> <p>It was agreed that the comment regarding short timescales would be addressed under question 7.</p>

	<p>objective three by reducing the ability of customers to take advantage of lower tariffs which overall means the DNO does not currently recover sufficient revenue from this group of customers. This would not appear to be supported by the proposed solution which reduces the overall revenues recovered from UMS by some 16%.</p>	
Electricity North West	<p>Yes, the proposal better meets the DCUSA general and charging objectives through the introduction of four new NHH UMS tariffs. This improves the cost reflectivity of the NHH UMS tariffs, where currently only one rate applies to all UMS regimes. The change proposal also introduces a seasonal timeband for the HH UMS tariff which is a more accurate representation of the cost that these customers impose on DNOs networks.</p>	Noted
Franck Latrémolière (speaking for himself only)	<p>The proposed modification removes some undue barriers to the use of pseudo half hourly metering systems. This is good for data quality in the settlement system, and probably good for competition in the provision of these metering services.</p> <p>The proposed modification also permits an improvement against charging methodology objective 3, in cases where the black time band has been set to cover predominantly night time periods. This is because it addresses the defect in the CDCM associated with the excessive coincidence correction factor that is applied to unmetered supplies as a result of the specific seasonal consumption pattern of street lighting. This looks quite successful in 12 areas; but not in the LPN and SHEPD areas, due to these DNOs' choice of black time bands. In LPN and SHEPD, there is a lot of daytime in the black time band, and therefore there remains a big discrepancy between what the coincidence factor data implies (street lights are on at the time of system peak) and what the time band data implies (street lights are on for only about half of the black time band).</p> <p>The issue is apparent in the models and results: uniquely in SHEPD and in LPN, the coincidence correction factor for unmetered is more than 25 per cent higher than the coincidence correction factor for LV half hourly loads (so that a street lighting load contributes much more to e. g. EHV costs than an equivalent load through a commercial or industrial meter), and category A continuous loads are charged more per unit than category B street lighting loads. Whilst it is theoretically possible that these odd patterns of charges are appropriate, the consultation does not put forward any reason</p>	<p>The Working Group noted that it is for DNOs to choose their own individual timebands. It was noted that the DCP 130 working Group has made it flexible by introducing a black timeband which DNOs can make different to their super-red timebands should they choose to do so.</p> <p>LPN noted that they believe that it is appropriate that at 'system peak' those users who are using the network receive the higher DUoS charge, which under this Change Proposal is the new 'black' time band. UMS is not solely street lighting but also includes street furniture, which will impact on the network especially at the system peak. For that reason LPN believe that it is appropriate that the 'black' time band covers the summer lunchtime and winter afternoon / evening peak in the LPN region.</p> <p>Following the consultation SSE Power Distribution have further reviewed its SHEPD timebands. The proposed SHEPD black/yellow timebands set in Appendix F of the Change Report are now different to those included in the DCP130 consultation. The CDCM methodology adjust charges on the basis of coloured timebands in</p>

	<p>to believe that it is appropriate in practice for these companies. I thought that even in these companies the time of peak for very many network assets would be in the winter early evening, i.e. at night.</p> <p>In cases where the proposal succeeds, its only material bad effect seems to be complexity, and given the general basis of the proposal I do not think that complexity could be removed without jeopardising the achievement of legitimate objectives.</p>	<p>order to ensure that, overall, they will approximately reflect the different contributions of different tariffs to the time of system peak. The previous black timeband included significant daylight time, which meant that unmetered supplies consumed about 50 per cent more power at the time of system peak than they do on average during the black timeband. The proposed black timeband now is predominately at night and therefore similar (in terms of unmetered supply load) to conditions at the time of system peak and results in more cost reflective charges.</p>
Northern Powergrid	Yes – We agree with the working group’s assessment.	Noted
Power Data Associates Ltd	<p>Yes – as per CP</p> <p>Although it is perceived that UMS is unresponsive load, where the prices vary so significantly between B/Y/G it will be interesting to see the innovative solutions that customers may adopt to seek to react to these “cost reflective” charges.</p>	Noted
ScottishPower Energy Retail	<p>We agree that the change better meets CDCM Objective 2, General Objective 2, and CDCM Objective 3. The change will introduce charges that are more cost reflective for a particular type of NHH UMS customer, as opposed to one averaged tariff across all types. This is more reflective of the costs being incurred by the DNO and will ensure that these are charged to suppliers in a more accurate way, hence facilitating effective competition.</p>	Noted
SmartestEnergy	<p>We agree with the Working Group that the Change Proposal better meets DCUSA Charging Objective one, two and three by reducing the differential between HH and NHH UMS tariffs. However, we do not understand what is meant by “encouraging customers and suppliers to choose the <u>appropriate</u> settlement approach.”</p> <p>We also agree that the proposal meets the DCUSA Charging objectives 2, 3 and 4.</p>	<p>The Working Group clarified with the respondent that the CP was seeking to remove the barrier between settlement approaches.</p>
SP Distribution and SP Manweb	Yes, we agree with the working group’s assessment.	Noted
SSE Supply	We agree with the reasons given in the consultation.	Noted

SSEPD SHEPD	Yes, we agree that the CP better facilitates general objective 1-3 and CDCM objective 1-4 for reasons assessed by the working group.	Noted
UK Power Networks	We believe this proposal better meets the CDCM and General Objectives by improving the cost reflectivity of HH UMS and NHH UMS through the introduction of STOD time bands and by the disaggregating the NHH UMS charges to reflect the seasonal pattern of use that is experienced by different UMS categories.	Noted
Western Power Distribution	It better facilitates CDCM objective 3.	Noted
<b>Question Four</b>	<b>Do you have any comments on the proposed legal text?</b>	
British Gas	<p>Paragraph 41 will need updating if DCP 134 is approved.</p> <p>Tables 8 and 9 need to be updated to reflect the new NHH UMS tariffs.</p> <p>We are not sure whether paragraph 42A (using sample data from pseudo HH meters) is consistent with the proposals to use approved switching regimes for the proportion of units in each time band and to set the UMS coincidence factor to 1.</p> <p>Overall, this change represents a significant change to the CDCM model and the consultation has provided very little detail on what has changed and why. It simply states that, amongst other changes, 26 new tables have been added, tables 2418 – 2443, however the prototype model provided with the consultation is missing tables 2440 - 2443. In the absence of a full description of the intended changes to the CDCM model we have not been able to fully check whether the changes made to legal text or the CDCM model are consistent with each other or with what was intended.</p>	<p>It was agreed that the Working Group cannot build DCP 134 into the legal text for DCP 130. The group agreed to review the legal text in light of the respondent's other comments.</p> <p>It was noted that the respondent did not believe that enough information was provided with the legal text. It was agreed that an appendix should be added to the Change Report to provide additional information on the changes that DCP 130 makes to the CDCM.</p>
Electricity North West	No	Noted
Franck Latrémolière (speaking for himself only)	<p>The proposed changes to the legal text seem clear and accurate.</p> <p>They highlight a defect (which I am probably to blame for) in the existing CDCM legal text: the text does not make it clear that off-peak tariffs in profiles 2 and 4 are calculated by reference to red/amber/green time bands, like other profile 2 and 4 tariffs, and not like unrestricted tariffs. For example paragraph 68 should probably say "with a single unrestricted unit rate" rather than "with a single unit rate", and paragraph 72 should talk</p>	Noted

	about “non-unrestricted tariffs” rather than “tariffs with several unit rates”. This change might be out of the scope of this change proposal, but perhaps it could be addressed as part of this modification by including a table showing explicitly which set of rules applies to which tariff.	
Northern Powergrid	Our initial observation is that the consultation implies that the NHH coincidence factor will be set to 1 for new UMS tariffs A (continuous), B (dusk to dawn) & C (half night and pre-dawn) and set to zero for new UMS tariff D (dawn to dusk). Is it also the intention to set the HH coincidence factor to 1 but phase it in over the three year rolling average? If the inputs are going to be fixed then this should be captured in the legal drafting, which is not the case at the moment. The legal drafting needs to undergo a thorough review after the final solution has been agreed.	The Working Group agreed that the legal text should be clarified.
Power Data Associates Ltd	Clause 42A – I think this should only be referring to NHH UMS, as the HH UMS forecast for the following year is derived based upon the historic profile used in the relevant DNO area. Should new para 42A be replacing the para 46? Why did the subsequent paragraph numbering increment? Should seek to limit the renumbering.	The Working Group agreed that the legal text should be clarified.
ScottishPower Energy Retail	No.	Noted
SmartestEnergy	No	Noted
SP Distribution and SP Manweb	None.	Noted
SSE Supply	No.	Noted
SSEPD SHEPD	No.	Noted
UK Power Networks	No we are content with the drafting provided by the working group.	Noted
Western Power Distribution	No	Noted
<b>Question Five</b>	<b>Are there any alternative solutions or matters that should be considered by the Working Group?</b>	
British Gas	We are not supportive of the proposal to proceed with option 2 for coincidence factors (see question 10). We believe option 1 is the correct	The Working Group noted that the different cost allocation methods between single rate tariffs and multi-

	<p>solution.</p> <p>We note that one of the inconsistencies being addressed by this change proposal is the difference in cost allocation between single rate tariffs and multi-rate tariffs. The working group could consider addressing this inconsistency for all tariffs at the same time, or explain why it is appropriate to address it for the UMS subset of customers ahead of other tariffs.</p>	<p>rate tariffs particularly affects UMS customers due to the excessive coincidence correction factor that is applied to unmetered supplies as a result of the specific seasonal consumption pattern of street lighting. The Working Group therefore believes it is appropriate to remove this inconsistency for UMS ahead of any solution for other customer groups.</p> <p>It was noted that all customers will be addressed under the DCMF MIG HH/NHH subgroup.</p>
Electricity North West	No	Noted
Franck Latrémolière (speaking for himself only)	<p>The working group should consider mandating a set of criteria that DNOs should use to define their black time bands, to avoid a situation in which the average load of street lighting during the black time band is a lot less than the load of street lighting at relevant times of system peak. A possible rule might be that the black time band must be almost entirely at night so that their use for unmetered supplies tariff does not create excessive distortions through coincidence correction factors.</p> <p>If, in any DNO area, many network assets peak at other times than black (e.g. during the day, whether in the summer or in the winter) then this should be reflected in tariffs through peaking probabilities; there is no need to distort the definition of CDCM time bands for that purpose.</p>	The Working Group noted the respondent's view and noted that the black timeband is defined based on the system peaks of each network and UMS may or may not be contributing to this.
Northern Powergrid	Not at this time.	Noted
Power Data Associates Ltd	In some DNO areas (eg WPD Swest & Swales) the black rate has become extremely high relative to the other units. Is this appropriate? Should some of the revenue being recovered through these units be collected through a smaller increase on a higher volume of units – ie yellow?	It was noted that in Swest there is very high scaling and this goes on the red and super red periods. Scaling is to be considered under DCP 123.
ScottishPower Energy Retail	None that we are aware of at this time.	Noted
SmartestEnergy	Yes – perhaps one of the Working Group would like to consider raising a change to the BSC to mandate HH for all UMS	It was noted that this sits outside of the scope of DCP 130
SP Distribution and	No.	Noted

SP Manweb		
SSE Supply	No.	Noted
SSEPD SHEPD	Not at this time.	Noted
UK Power Networks	No, we do not believe that there are other solutions. We support the application of STOD tariffs as we believe that these are more reflective of the usage patterns of users.	Noted
Western Power Distribution	No	Noted
<b>Question Six</b>	<b>Are you aware of any wider industry developments that may impact upon or be impacted by this CP? If so, please give details, and comment on whether the benefit of the change may outweigh the potential impact and whether the duration of the change is likely to be limited.</b>	<b>Working Group Comments</b>
British Gas	As mentioned above, if approved DCP 134 (notice period for changes to timebands) is likely to affect the proposed legal text.	Noted
Electricity North West	No	Noted
Franck Latrémolière (speaking for himself only)	What benefit of what change might outweigh the potential impact of what?	Noted
Northern Powergrid	There are a number of CDCM related changes being considered at the moment which could change the level of revenue recovery between customer groups and have a knock-on impact on the assessment of this change proposal. This change could also have a significant impact on the DCP135 'Clarification of CDCM changes' as it involves changes to the functionality of the CDCM model (new inputs and tariffs) rather than just changes to the inputs.	It was noted that this has been taken into account by DCP 135
Power Data Associates Ltd	No	Noted
ScottishPower Energy Retail	No.	Noted
SmartestEnergy	No	Noted
SP Distribution and	None.	Noted

SP Manweb		
SSE Supply	No.	Noted
SSEPD SHEPD	Our comments on this DCP are based upon consideration of its potential impacts on DUoS Tariffs in isolation. The cumulative/net effect of all DCPs currently being considered has not been modelled, therefore making an assessment of the combined impact on DUoS tariffs is difficult. Our opinions in this document are provided on that basis, and we urge that DCP's are progressed with some caution until these cumulative/net impacts can be modelled and assessed for each of the 14 LDSO Areas.	It was noted that the Working Group can only look at the impact of DCP 130 in isolation.
UK Power Networks	Work is progressing under the NHH / HH MIG Sub Group (also known as MIG 22), which is looking at similar issues which exist with metered tariffs. Consideration for the NHH UMS LDNO Tariffs as calculated within the EDCM does not appear to be considered, this needs to be corrected for this change to proceed.	The Working Group agreed that the EDCM would require amendment.
Western Power Distribution	No	Noted
<b>Question Seven</b>	<b>Are you supportive of the proposed implementation date of 1 April 2013?</b>	<b>Working Group Comments</b>
British Gas	<p>No, we would suggest an implementation date of 1 April 2014. 1 April 2013 seems quite a short notice period considering the impact this will have on various UMS customers, especially the new Category C NHH UMS who will receive a large price shock (average increase of 38%, max increase of 60%). We have a number of issues with the level of detail contained in the consultation.</p> <ul style="list-style-type: none"> <li>It has not been explained why the overall UMS customers will receive a reduction in DUoS costs of c. 16% (to be recovered by other CDCM users).</li> <li>There is a lack of detail provided on the changes made to the CDCM model which has not allowed us to be able to fully check whether the legal text and CDCM model are aligned with each other or what was intended.</li> <li>The revenue comparison contained in the consultation does not appear to be on a like for like basis as the volume of UMS units in</li> </ul>	<p>The Working Group discussed the respondent's comments. It was agreed that point 1 was not sufficient reason to delay implementation of the CP.</p> <p>For point 2 the group agreed that additional detail should be included in the change report.</p> <p>It was noted that the group is seeking to implement the CP in very tight timescales, which limits the time available to produce information to support the impact assessment of the CP.</p> <p>The Ofgem representative at the meeting noted that it is always preferable to produce a full set of analysis, even if this requires the Implementation Date to be pushed back. The group noted that for the Scottish DNOs there</p>

	<p>the updated CDCM models does not match the volume of UMS units in the base models for the majority of DNOs (c. 1.2% difference in total).</p> <ul style="list-style-type: none"> <li>From question 9, it also appears that the impact assessment has been carried out on estimated switching times whereas the intention is that tariffs will actually be set by using approved switching times. Therefore it is unclear at this point whether the tariffs included in the impact assessment will be subject to change once they are recalculated based on approved switching times.</li> </ul> <p>For the reasons above, as well as our view that the working group should adopt option 1 for the setting of HH UMS coincidence factors (for which no impact assessment has been presented), we believe that it would be appropriate to delay any implementation until 1 April 2014 to give time for a more informative consultation process and a more accurate impact assessment.</p>	is political pressure to ensure the change goes through sooner rather than later.
Electricity North West	Yes	Noted
Franck Latrémolière (speaking for himself only)	It is ambitious.	Noted
Northern Powergrid	<p>Consideration needs to be given to the practicalities of the proposed implementation date and the robustness of the enactment of the change that can be achieved in these timescales. Consideration needs to be given to the following:</p> <ul style="list-style-type: none"> <li>What market domain data (MDD) changes are required? Do we need new SSCs? MTCs? And TPRs? Again what is the lead time in setting this up and does this need to be completed in advance of setting indicative tariffs? We would not want commence MDD changes until Ofgem had approved the changes.</li> <li>Can DNOs publish indicative tariffs in December detailing new tariffs that are not live in MDD?</li> <li>What are the impacts on the billing system?</li> </ul> <p>It would be good to see an implementation plan with the change report that details what needs to be achieved prior to setting indicative charges in December, and what needs to be in place prior to the new tariffs going live</p>	The Working Group noted that from the point when indicatives are issued there will be a period of three to four months to update MDD.

	the following April.	
Power Data Associates Ltd	Yes	Noted
ScottishPower Energy Retail	We support the introduction of these tariffs from the start of a charging year. We therefore support 1 April 2013 on the condition that these tariffs will be provided in DNOs' indicative charging statements published in December 2012. If this cannot be done, 1 April 2014 would be the next appropriate date.	Noted
SmartestEnergy	Yes	Noted
SP Distribution and SP Manweb	Yes.	Noted
SSE Supply	Yes.	Noted
SSEPD SHEPD	Yes.	Noted
UK Power Networks	Yes we are supportive, although we agree with the working groups view that we need to have a decision from Ofgem on whether they will approve the change as early as possible and certainly no later than early December, in order to gain internal approval and use for publication of indicative charges for April 2013.	Noted
Western Power Distribution	Yes	Noted
<b>Question Eight</b>	<b>DNOs, do you agree with the Working Group's assessment that if an Ofgem decision was received by 5 December 2012, this would permit use for the April 2013 indicative tariffs?</b>	<b>Working Group Comments</b>
British Gas	N/A	
Electricity North West	Electricity North West support an early decision date from Ofgem as this will assist in the production of indicative tariffs. However, if the decision is made after the 5 <sup>th</sup> December, we anticipate that we will still be able to incorporate it into the production of indicatives tariffs for April 2013.	Noted
Franck Latrémolière (speaking for himself only)	N/A	
Northern Powergrid	These proposed timescales for Ofgem providing a decision are tight in order to make the changes to the charges and get internal sign-off of the	Noted

	charges. We would suggest that it would be preferable for an Ofgem decision to be received by mid-November at the latest.	
Power Data Associates Ltd	I would hope Ofgem can make a quick decision. And that DNOs can act promptly to incorporate these approaches into their indicative prices published around Christmas.	Noted
ScottishPower Energy Retail	N/A	
SmartestEnergy	N/A	
SP Distribution and SP Manweb	Yes.	Noted
SSE Supply	Yes.	Noted
SSEPD SHEPD	Yes. However if a decision is not received before 5 December 2012, we may not reflect this CP on our April 13 indicative tariffs, but will apply to the final tariffs.	Noted
UK Power Networks	We would welcome a decision from Ofgem as early as possible, in order to be able to use the model for the calculation and publication of indicative charges for April 2013. A late December approval (after the 5 December 2012 as indicated in the consultation paper) could result in indicative charges being calculated using the existing CDCM model 100, with only the final charges using the revised model. Late notification would be detrimental to Suppliers and Customers.	Noted
Western Power Distribution	Yes. If a decision was received after 5 <sup>th</sup> December DNOs could not guarantee use in indicatives.	Noted.
<b>Question Nine</b>	<b>The input data for table 1064 (Average Split of Rate 1 Units by Special Distribution Time Band) has been determined based on estimated switching times for each category. It is the intention of the Working Group to re-calculate values for this table for each DNO area based on approved switching regimes. These values would then only be re-calculated where there is a change of timeband. Do you agree with this approach? Please give your rationale.</b>	<b>Working Group Comments</b>
British Gas	We do not understand why there should necessarily be a link between the time bands that DNOs declare as their charging periods and the approved switching regimes for UMS. It would seem appropriate that if approved	The Working Group noted that the approved switching regimes are unlikely to change unless there is a change to the timebands. The Working Group noted that DCP

	<p>switching regimes change then the values should be recalculated, noting that the 3 year average approach for this input would militate against price shocks.</p> <p>We also note that the impact assessment has been carried out on estimated switching times whereas the intention is that tariffs will actually be set by using approved switching times. Therefore it is unclear at this point whether the tariffs included in the impact assessment will be subject to significant change once they are recalculated based on approved switching times, however we note from the recirculation of appendix F during this consultation process that small changes in these data items can have material impacts on the resultant tariffs.</p>	<p>130 would not prevent DNOs from changing their switching regimes should they choose to do so.</p> <p>It was noted that the impact assessment was based on approved switching regimes.</p>
Electricity North West	<p>Yes, this seems a reasonable approach as the profiles should not change substantially year on year. Using actual data can be misleading as some NHH UMS mpans are de-energised partway through the year as they are transferred to HH UMS (due to the assets being adopted by the local council).</p>	Noted
Franck Latrémolière (speaking for himself only)	<p>The question implies that a working group will be making calculations that will then be used to set tariffs. This takes the responsibility for implementing the methodology away from individual DNOs, without a good reason.</p> <p>I think that it should be the continuing responsibility of each DNO to satisfy itself that the data are correct and representative. Perhaps in practice this might mean that no recalculation is needed, but I do not support elevating that to a mandatory approach.</p>	See response to British Gas comment.
Northern Powergrid	<p>The methodology by which this is achieved, and the associated data sources, needs to be defined to ensure that this is achieved on a consistent basis by all DNOs. This could be achieved by an update to the User Manual.</p>	Noted
Power Data Associates Ltd	<p>Due to the price sensitivity of the time bands the accuracy of this calculation has to be done extremely carefully. The seasonal nature of the charging means that the number of weekends in relevant period has an impact.</p>	Noted
ScottishPower Energy Retail	<p>Yes, this should maintain an accurate reflection of the volumes relevant to the revised time period.</p>	Noted
SmartestEnergy	<p>Yes, it is better for the switching times to be based on approved, rather</p>	It was agreed that additional detail should be included in

	than estimated regimes. However, it is not clear when the yellow time band would be utilised.	the Change Report.
SP Distribution and SP Manweb	Who will be calculating the values for table 1064? The process for re-calculating the values will need to be clearly defined.	Noted
SSE Supply	Yes, but the ongoing impact of the Lighting Authorities efficiency drives should be reviewed on a periodic basis.	It was noted that this should not impact on the profiles.
SSEPD SHEPD	<p>We agree that the values be re-calculated to facilitate cost reflective calculation.</p> <p>However we are against either fixing these values until a change of timeband. As we are proposing some new tariffs the resulting sign-ups are uncertain and therefore the value we assessed today may change significantly tomorrow. Hence we propose that these values be reviewed annually instead.</p> <p>Also we are against the idea of associating the change of these values with a change of timeband. Due to the effect of DCP134, a change of timeband is subject to a minimum of 15 months notice, therefore would set barriers to cost reflectivity if we are restricted to revise these values until 15 months after we identify a need for change.</p>	The Working Group noted that other respondents had also suggested re-calculation. It was agreed that DCP 130 will not prevent DNOs from re-calculating values. The group noted that the proportion of units are unlikely to change unless there is a change to the distribution time-bands.
UK Power Networks	Yes we believe that the approach suggested within the working group is correct, and we agree with recalculating the values using the approved switching times would seem appropriate for the initial population of the model, with any recalculation only taking place when there is a change of time band.	Noted
Western Power Distribution	Yes. The switching times are based on actual dawn and dusk which does not change year on year.	Noted
<b>Question 10</b>	<p><b>The Working Group noted that there are three potential options for determining the co-incidence factors for the new UMS tariffs.</b></p> <p><b>1. Big bang for NHH and HH – this option will create a step change for all UMS tariffs.</b></p>	<b>Working Group Comments</b>

	<p><b>2. Change NHH immediately and leave HH as a gradual change – this options is what is being demonstrated in the attached prices provided as Appendix F</b></p> <p><b>3. Do a gradual change for all</b></p> <p><b>It was the view of the Working Group that option 2 is the preferable option. Do you agree? Please provide your rationale.</b></p>	
British Gas	<p>We do not agree with the working groups' preference. We do not think that the gradual change to HH co-incidence factors contained in option 2 is consistent with the purpose or principle of the 3 year average approach to setting coincidence factors (and load factors and proportion of units in time bands) in either the CDCM methodology as it currently stands or the proposed amended legal text contained in this consultation.</p> <p>The purpose of the 3 year average approach is to smooth out changes over time of a data set calculated on a consistent basis, not to smooth out fundamental changes to the basis on which the data items are calculated.</p> <p>Our interpretation of the 3 year average approach for these CDCM inputs is that a methodology must be agreed to calculate the coincidence factor (and load factor and proportion of units in each time band), and then the DNO must apply that approach to the most recent 3 years of data. For the HH and NHH UMS coincidence factors under this change proposal this would mean setting it to 1 from implementation. Our preference is therefore for option 1. It would have been useful to understand the impact on tariffs and revenues for all of the options listed.</p> <p>Option 2 mixes methodologies for calculating coincidence factors and effectively represents a transitional implementation. It is also worth noting that the tariff comparisons provided do not inform users of the impact on the tariffs once these transitional arrangements have expired.</p>	<p>The respondent noted his understanding of the purpose and principle of the three year approach was to agree the methodology for calculating the co-incidence factor and use an average of the last three year's data. It is not the average value of the last three years values from the CDCM. The respondent noted that he believes some DNOs may be using this incorrect approach. If coincidence factors were to be recalculated based on an average of the last three year's data then the difference between option 1 and 2 will not be that great.</p>
Electricity North West	<p>Yes, we agree that option 2 is the appropriate solution, as it will reduce volatility. We also accept that there is a strong case for option 1, and would support this as an alternative. Option 3 is not cost reflective and should not be progressed.</p>	Noted
Franck Latrémolière (speaking for himself)	<p>It does not make sense to me to set tariffs on the basis of input data that are suspected to be erroneous, even on a transitional basis. I accept that it</p>	Noted

only)	<p>might well make sense to reduce suppliers' exposure to errors, corrections and other data fluctuations by phasing or delaying changes in the tariffs to be applied. But it makes no sense to try and achieve (in part) that legitimate objective through the illegitimate means of asking DNOs to populate models with data that do not reflect the best information that they have.</p> <p>I appreciate that this complaint should ideally have been directed against DCP087 rather than the present change proposal. But it is never too late to start doing the right thing.</p>	
Northern Powergrid	<p>We agree that Option 2 will create less of a step change if:</p> <ul style="list-style-type: none"> <li>• the NHH coincidence factor are set to 1 from April 2013 (i.e. because these are new tariffs that the coincidence fact is fixed from day one);and</li> <li>• the HH coincidence factors are also be set to 1 but then smoothed by calculating on a 3-year average basis (i.e. the latest coincidence factor used for charge setting will be fixed but the three year smoothing of these inputs in the charging methodology would still be adhered to).</li> </ul> <p>The consultation states that the coincidence factors should be very close to one. Experience has shown that this is very much dependent on the time and date of the system peak. If the system peak is in December or January in the early evening on a working day then this statement is likely to be true but if the system peak is outside these parameter then very different result can be found.</p>	Noted
Power Data Associates Ltd	<p>This is only a concern for certain DNO areas where the values have been inappropriately low. If adjusting the values to a realistic level still result in a net reduction in UMS revenue, then it should be applied from 1<sup>st</sup> April 2013. Otherwise, the first year should show no change in revenue, then a progressive increase over the following three years.</p> <p>The concern with option 2 is that UMS customers as a whole are likely to see a reduction in their overall contribution to DUoS and then a faster increase in the subsequent years. This is not ideal. Ideally, there should be a no drop in revenue from the group of UMS customers in 2013/14.</p>	Noted
ScottishPower Energy Retail	<p>Yes, it is more accurate to use coincidence factors specific to each of the new NHH UMS tariffs as opposed to the average across all four.</p>	Noted

SmartestEnergy	We feel that option 1 would be more appropriate as we support this change and think it would be beneficial to do at once.	Noted
SP Distribution and SP Manweb	Yes, we agree with the working group's assessment that Option 2 would be preferable.	Noted
SSE Supply	Yes, option 2 is best.	Noted
SSEPD SHEPD	We agree with the working group that option 2 is the preferable option. The NHH UMS tariffs are brand new so changes should be implemented immediately; HH ones on the other hand can be implemented gradually to reduce short term disturbance to affected customers.	Noted
UK Power Networks	We agree with the approach to use option two as proposed by the working group, as with the NHH tariffs being fundamentally different to those currently in place it would seem appropriate to calculate new co-incidence factors. However as the proposed HH tariff is similar to the existing tariff, although there is a different time band applied (STOD and not TOD), we would agree that changes to HH will be gradually applied in line with DCUSA following the implementation of DCP087 to smooth the inputs over a three year period. We do not believe that either option one or three are appropriate to use.	Noted
Western Power Distribution	I think all 3 are viable options. Option 2 has the benefit of being part gradual and part big bang and is a compromise of 1and 3.	Noted
<b>Question 11</b>	<b>Do you have any further comments?</b>	<b>Working Group Comments</b>
British Gas	No.	Noted
Electricity North West	A change to the legal text will be required if the working group do not select option 2 in question 10.	Noted
Franck Latrémolière (speaking for himself only)	I don't think that the process of piecemeal modification of the charging methodologies on the basis of change proposals targeting specific problems is likely to lead to good charging methodologies. Here, the problem is that the conflict at the heart of the CDCM between methods based on peaking probabilities and methods based on coincidence factors is maintained, and possibly further embedded in the methodology	It was noted that the first point is under consideration by the DCMF MIG HH/NHH working group.  It was noted that the second point is not specific to DCP 130

	<p>as a result of an increase in complexity. Perhaps it would have been better to start by deciding whether the demand that drives network capacity is demand at the instant of system peak (or some kind of triad concept), or demand across several hundred hours of some black/red/super-red/whatever time band. If both concepts remain used without a clear rationale for the different roles that they play, risks of undue complexity and possible discrepancies will remain.</p> <p>I do not understand question 2 about the “principles of the CP”. It seems to appear in many change proposal consultations. I think that it should be replaced with something more precise.</p>	
Northern Powergrid	<p>The consultation states that UMS coincidence factors are being set to either one or zero. However, the same data that is used to calculate the coincidence factors is also used to calculate the load factors. How are load factors being treated/calculated under this proposal?</p> <p>More detail of whether these are to be fixed, or not, is required and if they are not going to be fixed, what process is to be used to calculate them?</p>	The Working Group agreed that information on the calculation of coincidence factors and load factors should be included in the DCP 130 Change Report.
Power Data Associates Ltd	<p>It is unfortunate that the delays by the DCUSA Panel in agreeing the funding for the CDCM model work has constrained the consideration of the model outputs to the consultation period. If the revised models had been prepared earlier the working group could have better understood/reviewed/considered the implications of this change.</p>	Noted
ScottishPower Energy Retail	<p>We note that the proposal sets out that the UMS time bands will mirror existing time bands. Should these diverge at any point in the future this will have system impacts in creating a further set of time bands (on top of the existing RAG and super-red). An increase in the number of time bands that are required increases the risk of manual error and erroneous charging.</p>	Noted
SmartestEnergy	No	Noted
SP Distribution and SP Manweb	None at this time.	Noted
SSE Supply	No.	Noted
SSEPD SHEPD	Not at this time.	Noted
UK Power Networks	No	Noted
Western Power	No	Noted

Distribution		
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