DCUSA CHANGE REPORT

DCP 204 - Smart Metering Related Amendments to Schedule 8

1 PURPOSE

1.1 This document is issued in accordance with Clause 11.20 of the DCUSA, and details DCP 204 – Smart Metering Related Amendments to Schedule 8. The voting process for the proposed variation and the timetable of the progression of the Change Proposal (CP) through the DCUSA Change Control Process is set out in this document.

1.2 Parties are invited to consider the proposed amendment (Attachment 1) and submit their votes using the Voting form (Attachment 2) to dcusa@electralink.co.uk by **Friday,11 December 2015**.

Comment [LN1]: When the Report is issued for voting the cover email need to make it very clear that votes previously submitted do not count in this voting round. Ie.. must re-vote

2 BACKGROUND AND SUMMARY OF DCP 204

2.1 DCP 204 seeks to update DCUSA Schedule 8 (Demand Control) to ensure that it remains relevant for smart metering technologies. The key principles of DCP 204 are as follows:

- To replicate existing functionality around tariff time switching and load switching for a smart regime. The CP is not seeking to introduce a like for like replacement but rather to replicate the method through smart metering. It should be noted that DCP 204 is not placing any obligations on Parties to replace the existing functionality of the Radio Teleswitch system.

- To simplify the security restriction notice process, in a way that describes an escalating process supported by different types of notice.

- To mandate randomisation, for all meters that support randomisation, up to a period of 600 seconds.

- To introduce a standard template that all Distributors will use to notify Suppliers of demand controlled areas.

2.2 DCUSA Schedule 8 relates to Demand Control measures which can be initiated by Distributors to preserve security of supply and integrity of their networks and/or to avoid, minimise or defer network investment. For Distributors, the ability to manage load switching arrangements is central to the effectiveness of this Schedule.

2.3 Discussions regarding the implications of the change of switching technology between Ofgem, Distributors and Suppliers, and other discussions at an Energy Networks Association (ENA) Working Group and the Smart Grids Forum Work stream 6 sub group have resulted in DCP 204 being raised by Scottish Hydro Electric Power Distribution plc.

2.4 The intent of this CP is to amend DCUSA Schedule 8 to reflect the migration of load switching technologies deployed by Suppliers in customer premises from established devices, such as radio teleswitching via the Radio Teleswitch Service (RTS) and timeswitches, to smart metering technologies. It is possible that existing switching devices will become redundant following the completion of the smart metering roll out.

2.5 The CP seeks to replicate the existing functionality afforded by existing metering systems (around tariff time switching and load switching) to Distributors in a Smart Metering regime and also seeks to clarify and/or simplify aspects of the Schedule. It should be noted that the CP is not seeking to introduce a like for like replacement but rather to replicate the method through smart metering.

2.6 This is the second Change Report to be issued in respect of DCP 204. The CP was initially sent to Ofgem for decision on 13 May 2015.

2.7 On 19 June 2015, Ofgem sent the CP back to the Working Group and directed that further consideration be given to the CP. Ofgem's send back letter is provided as Attachment 8. Information on Ofgem's concerns and how the Working Group has sought to address these is provided in section 8 below.

2.8 Following responses received from the first DCP 204 consultation (see section 5) and review of these comments by the DCP 204 Working Group, the Working Group has agreed that the following key principles will be incorporated into the DCP 204 legal drafting.

Load Switching

2.9 The term "Load Switching Regime" has been added to Schedule 8. This amendment has been made to reflect the additional load management functionality that smart meters provide, and which could be utilised to support the demand control processes set out in Schedule 8. This includes, but is not limited to, functions such as changing the Standard Settlement Configuration (SSC), randomisation and load limiting that could be used to control demand in Load Managed Areas.

2.10 In addition, the term "Load Switching Device" has been added to Schedule 8, defining such as equipment which switches or has the capability to undertake a Load Switching Regime. Additionally, the term "Auxiliary Load Control Switch" has been added which means a switch which is integral to a Smart Metering System which can switch electrical loads in the premises of a Customer.

Simplification and clarification of process and notices

2.11 The current notices defined in Schedule 8 and the differences between each type of notice are not currently very clear. The proposed legal text has been revised to replace Provisional Security Restriction Notices (SRNs) with an advisory notice and remove reference to a 'Firm' SRN. The revised proposed legal text for Schedule 8 is structured in way that describes an escalating process supported by the different types of notice.

2.12 The following table describes the notices that can be issued by Distributors and the associated obligations, which are reflected in the revised legal text:

Notice	**Description**	**Existing Obligations (which will continue to apply)**	**New and Additional Obligations**
Advisory notice	Issued (as per clause 4.1) as an early warning of potential operational constraints on an area of the network.		The Distributor will provide an advisory notice.
Load Managed Area Notice	Issued (as per clause 5.1) as a formal notification that changes in demand may affect the security of Supply.	• When replacing any metering equipment, Suppliers must ensure that the replacement equipment replicates the load switching times of the equipment being removed. • Where the Supplier is not able to replicate the current switching times or where they wish to change those times they must consult and agree alternative arrangements with the Distributor before doing so.	Distributors will provide Suppliers with a list of affected Metering Point Administration Numbers (MPANs)[1].
Security Restriction Notice (SRN)	Issued (as per clause 7.1) as a formal notification	As for Load Managed Area Notices, additionally:The Distributor may request that	Distributors will provide Suppliers with a list of

[1] Currently Load Managed Area Notices are issued at postcode level.

	that changes in demand will affect the security of Supply.	Suppliers make changes to Load Switching Regimes in the affected area to reduce the coincidence of demand in the specified area.	MPANs.The Distributor may request that Suppliers make changes to the Randomised Offset Limit in the affected area to reduce the coincidence of demand in the specified area.
Emergency Security Restriction Notice[2] (Emergency SRN)	Issued (as per clause 8.1) as a formal notification that there is an immediate risk to the security of Supply.	As for SRNs, additionally the Distributor may also issue a Compliance Notice	• Distributors will provide Suppliers with a list of MPANs. • The Distributor may request that Suppliers make changes to the Randomised Offset Limit in the affected area to reduce the coincidence of demand in the specified area.
Compliance Notice	Issued (as per clause 7.6 & 8.6)	• Distributor requests the Supplier to change, at its own cost, Load Switching Regimes to another that shall not have a material effect on the security of supply, • take such action that the Distributor considers reasonable • The Distributor may, with no prior notice, de-energise metering points in order to maintain the security of supply.	A request to adjust the Randomised Offset Limit

[2] This notice can be served at any time i.e. it is not just restricted to Load Managed Areas or areas where an SRN has already been issued.

2.13 It should be noted that the issue of an Emergency Security Restriction Notice need not be restricted to Load Managed Areas. This is an existing situation and is unaffected by this CP.

Existing Arrangements

2.14 The introduction of smart metering and the Data and Communications Company (DCC) will result in changes to how remote load control and switching instructions (for both static and dynamic arrangements) are issued. Static switching is currently achieved using a mixture of technologies, including; time switches, programmable meters and RTS. Dynamic switching is principally achieved by using the RTS. Across Great Britain approximately 5.6 million customers rely on existing technologies to change tariff registers. Many of these devices also directly switch the customers load at the same time that the tariff rate changes thus ensuring that heating and water heating take advantage of cheaper rate energy. For approximately 1.8 million customers their electrical storage and immersion heating is controlled remotely via the RTS.

2.15 The RTS is operated by the ENA on behalf of Distributors and typically used to control the switching of Non Half Hourly tariff registers and in many cases directly switch customer's load. Messages are sent via the BBC's 198 kHz long wave network to a teleswitch device located within the customer's property which in turn switches metering registers and may directly control customers load.

~~2.15~~2.16 The transition to smart meters will remove the DNO's ability carry out load switching of meters and, thus, remove the DNOs ability to reduce network load via this means. –It is noted that it is outside of the scope of DCP 204 to consider this issue.

Proposed New Arrangements

~~2.16~~2.17 Under proposed smart arrangements, the DCC will process requests from Suppliers to remotely switch registers and control load and will send commands to be applied by the relevant smart meter.

~~2.17~~2.18 Existing load which is currently controlled by RTS equipment, time switches and programmable meters will effectively become synchronised as a result of the increased accuracy of smart meters. This will lead to a reduction in the diversity of load switching that the current arrangements deliver (+/- 3.5 minutes either side of the set switching time for RTS controlled devices, unknown for other equipment such as timeswitches and programmable meters). Unless mitigating action is taken Distributors (at distribution and grid level) are likely to see additional contributions to network loading around programmed load switching times.

~~2.18~~2.19 There are also a range of other reasons why unnecessary load coincidence needs to be avoided and why clarity is required for timeswitching arrangements in smart. These reasons include:

- Distributors need to minimise voltage step change issues associated with simultaneous switching of material load;
- Distributors need to maximise network utilisation by staggering switching times to allow load switched on earlier to fall or drop off before switching on additional load;
- NGET and generators need a predictable load pick up without any material step changes;
- Customers need to know the times when the off peak load is switched and assurance that they are being charged at the appropriate off-peak rate;
- Suppliers and Elexon need to know the times when the off peak load is switched; and the total volume of load switched in each time period for supply volume allocation purposes. These aspects are being considered by the Profiling and Settlement Review Group (PSRG) including via its consultation on Settlement of Dynamically Switched Meters which is available on the Elexon website3;
- Unnecessary load coincidence around timeswitching can be avoided through the application of timeswitching randomisation to smart metering systems. The

[3] https://www.elexon.co.uk/wp-content/uploads/2014/06/PSRG_Dynamic_Switching_Responses_v1.0.pdf
https://www.elexon.co.uk/wp-content/uploads/2014/11/HH_Settlement_Dynamically_Switched_Meters_IA_Collated-Responses.pdf

Working Group considers that the key features of appropriate randomisation should include:

- Randomisation must not be over a period greater than the interval between defined settlement periods (i.e. 30 minutes);
- Hardcoded limits (in SMETS2 or the GB Companion Specification) shouldn't create future restriction in the functionality;
- Distributors should agree both the basic switching times and the Randomised Offset Limit with Suppliers via DCUSA;
- The applied Randomised Offset criteria must be capable of amendment as required to satisfy the future requirements of smart grids. The process for agreeing any changes should be via DCUSA;
- The Randomised Offset Limit applied should follow a generic consistent set of rules across the whole of GB. In Load Managed Areas, different rules may be required and these should be governed via DCUSA;
- Rules need to be applied to all switching regime types i.e. static, semi-static and dynamic regimes; and
- In future there may be a need to apply randomisation to "inferred" switching times, i.e. where load is affected by customer's response to a price signal via future time-of-use tariffs.

~~2.19~~2.20 Attachment 3 to this document is a paper entitled Randomisation Offset Limit. This document was created by the ENA Smart Metering Steering Group and presented to the Department of Energy & Climate Change (DECC) SMIP Technical and Business Design Group, its purpose is to explore the requirements associated with the application of a Randomised Offset Limit as applied to smart meters. The document explains why randomisation is required and provides options explaining how it could be applied. Following a review of the responses to the DCP 204 consultation, the DCP 204 legal text sets the Randomised Offset Limit to a value of no less than 600 seconds (10 minutes).

~~2.20~~2.21 The Working Group note that randomisation is a feature of smart metering that has already been agreed with DECC for inclusion in SMETS 2. DCP 204 is therefore not introducing randomisation but rather seeking to define the value of randomisation, i.e. up to no less than 600 seconds.

3 WORKING GROUP

Comment [RT2]: Correct numbering

4.1 The DCUSA Panel established a Working Group to assess DCP 204. This Working Group consists of DNO, Supplier, Ofgem and DECC representatives. Meetings were held in open session and the minutes and papers of each meeting are available on the DCUSA website – www.dcusa.co.uk.

4.2 The Working Group developed ~~a~~ two consultation documents (Attachment X) to gather information and feedback from market participants.

5 DCP 204 CONSULTATION ONE

5.1 The first DCP 204 consultation was issued on 25 July 2014 and there were 11 responses received.

5.2 A summary of the responses received, and the Working Group's conclusions are set out below. The full set of responses and the Working Group's comments are provided in Attachment 4.

Question 1 - Do you understand the intent of the CP?

5.3 The Working Group noted that all consultation respondents understood the intent of the CP.

Question 2 - Are you supportive of the principles established by this proposal?

5.4 The Working Group noted that ten of the eleven respondents were supportive of the principles established by the CP.

5.5 One respondent suggested that whilst they understand the principle of the CP, they believe that there should be a cost benefit been carried out to establish whether the proposed changes to DCUSA are proportionate to the risk. The Working Group discussed this comment and considered whether the Change Report should include information on the costs and benefits. It was agreed that DCP 204 is clarification of existing obligations and seeks to make sure that they are fit for purpose to meet the requirements of changing technologies and, thus, the need for a cost benefit has not been identified.

5.6 Another respondent highlighted that the current Radio Teleswitch metering technology was developed in the 1980s and expressed their concern that to try and replicate this is unnecessary and disproportionate to the risk. In response, the Working Group acknowledged that DCP 204 is not a like for like replacement of the arrangements that are currently in place. The intent of the CP is to replicate the effect of the current arrangements so that they work under smart metering, the effect being to ensure that the capacity of the network is not exceeded. In defining the proposal, the group has considered the requirements of the various industry parties and has sought to reach a balance between the varying needs of parties.

5.7 The Ofgem representative on the Working Group cautioned that the CP must be flexible enough to allow further benefits of smart metering to be realised in the future. In response, the Working Group noted that DCP 204 does not preclude the benefits of smart metering being realised in the future, it ensures that the security of supply is not jeopardised by the functionality that smart metering provides. It was observed that this area may need to be re-visited again as any move to more dynamic switching will result in a move away from fixed switching times. However, as this should align with the implementation of HH settlement in 2020 it would be more appropriate to revisit this area then, rather than trying to future proof DCP 204.

Question 3 - Are there any unintended consequences of this proposal?

5.8 The Working Group noted that six respondents identified unintended consequences of the proposal.

5.9 A Supplier respondent highlighted that Suppliers would need to understand what switching times are in operation at a particular customer's property before they attend so that they can replicate these. The group noted that Suppliers will seek to replicate the existing set up based on the information available to them (i.e. which switching regime they are on). It was noted that there is a risk that the Supplier may not have accurate information but this is a wider industry issue and data cleansing is being discussed in other industry forums.

5.10 The group noted, in response to another Supplier's comment that the elements of the CP relating to randomisation will not apply to SMETS1 meters as they will not have the appropriate capabilities.

5.11 The Working Group agreed that explicit references to SMETS versions should not be included within the DCP 204 legal text, as this would risk accidentally excluding SMETS1 meters that do have this capability despite not being mandated by SMETS1.

5.12 Another respondent cautioned that care needs to be taken to ensure that the proposed changes do not impact on the processes for legacy meters, prior to being changed as part of the Smart Meter roll out, which could result in Parties needing to make changes to systems and processes and incur costs relating to legacy meters. The Working Group noted the intent of DCP 204 is not to impact upon the existing processes.

5.13 One respondent noted that, whilst it may be out of scope for DCP 204, further work may be required to develop arrangements for embedded networks.

5.14 A Supplier respondent cautioned that DCP 204 could lead to costs being reallocated from Distributors to Suppliers if Load Managed Areas are not managed effectively. This respondent also cautioned that changes to a customer's load switching times or even the randomisation settings within their meter as a consequence of issues with coincidence of demand will require effective customer communication to ensure customers fully understand the precise timings for any "off peak" periods and when they should switch appliances on or off. The Working Group noted the respondent's comments and re-worded the confidentiality clause in Schedule 8 to enable Suppliers to share information with affected customers.

Question 4 - Do you consider that the proposal better facilitates the DCUSA general objectives?

5.15 The Working Group noted that the majority of consultation respondents agreed that the proposal better facilitates the DCUSA objectives. The following table outlines which DCUSA Objectives respondents specifically stated as being better facilitated by the CP:

DCUSA General Objectives	No. Of Respondents that agree it is better facilitated
Objective 1	8
Objective 2	0
Objective 3	0
Objective 4	1

Objective 5	0

5.16 The Working Group noted that the majority of respondents agree that objective one will be better met. One respondent also believed that general objective four would be met.

5.17 One respondent stated the proposed Supplier obligations appear to apply to all Smart Metering Systems which the respondent did not agree was proportionate and therefore would not better facilitate the applicable objectives. The respondent suggested that they believe any Supplier obligations should only apply to SMETS 2 meters. The group agreed that the legal text should refer to where functionality is available rather than a reference to a SMETS version as indicated earlier under paragraph 5.11 of this change report.

5.18 Another respondent noted that they agree that the CP better facilitates the DCUSA objectives but there is a need for Distributors and Suppliers to work together to manage customer communications if there is a requirement for an Load Managed Area (LMA). The Working Group reviewed the Schedule 8 confidentiality clause to enable Suppliers to share information with customers.

5.19 The Working Group noted that DCP 204 had the potential to negatively impact competition by increasing market complexity but looking at the CP in the round it better facilitates the DCUSA objectives. Working Group members cautioned that changes to the DCUSA should not discourage innovation and investment in research on new ways of improving security of supply.

Question 5 - This proposal requires that randomised offset rules are applied to all smart metering systems. Do you agree with this proposal?

5.20 It was noted by the Working Group that eight of the eleven respondents agreed that randomisation should be applied to all metering systems.

5.21 Of the respondents that agreed, one Distributor respondent noted that they: "*expect the Supplier to take all measures in both its choice of metering systems and in the wording of its contracts with its customers to ensure that no restrictions upon Randomisation occur. This is vitally important for both distribution network operator and for the national* *electricity transmission system operator in avoiding step changes in consumption that increase system instability risk due to lack of Randomisation.*"

5.22 Another respondent that agreed with the proposal to apply Randomised Offset rules to all smart metering systems stated that "*it will avoid load associated with specific Load Switching Regimes being connected at the same time. Currently with existing technology connection drift occurs*".

5.23 A Supplier respondent cautioned that the DCUSA requirements should not duplicate anything that is contained within the SMETS 2 specification. The Working Group agreed that they would not wish for there to be duplication.

5.24 Another Supplier respondent suggested that randomisation should only be applied in LMAs, not across the whole country. The group discussed this comment and noted that all load is already randomised in the sense that you do not know what the clock settings are.

5.25 This respondent also highlighted that the Transitional Security Expert Group (TSEG) is considering randomisation for security reasons and suggested that the Working Group note this when considering randomisation parameters as part of this CP. The Working Group noted that the main consideration of the TSEG is the impact on the grid. National Grid has fed its views to the DCP 204 Working Group and has not raised any concerns with the 600 second randomisation value chosen.

Question 6 - Which is the most appropriate Industry Code for the rules associated with randomised offset to be governed under?

5.26 The Working Group noted that the majority of respondents felt that the DCUSA would be the most appropriate code. The following table details the responses split by respondent type.

Which is the most appropriate Industry Code for the rules associated with randomised offset to be governed under?							
Respondent type	**DCUSA**	**BSC**	**SEC**	**Engineering Requirement**	**Split across codes**	**No preference**	**Total**
DNO	3	1			1	1	**6**
Supplier	2		1		1		**4**
IDNO				1			**1**
Total	**5**	**1**	**1**	**1**	**2**	**1**	**11**

5.27 Having reviewed the consultation responses, the Working Group noted that the majority of respondents believe the DCUSA is the most appropriate code. The Working Group has also been advised by DECC that their preference would be for the rules to sit within DCUSA.

5.28 The Working Group agreed that it is appropriate for the randomisation rules to be the DCUSA rather than the SEC because:

5.29 Communication between Parties and the smart meters only is defined within SEC, how you operate the smart meters is outside of the scope of the SEC

5.30 Any change to the way in which randomisation is applied is determined by the Distributors and National Grid where constraints occur.

Question 7 - What are your views regarding the value (in seconds) that should be defined in DCUSA as the minimum randomised offset limit?

5.31 The Working Group noted that there were varying responses to this question. These are summarised in the table below.

What are your views regarding the value (in seconds) that should be defined in DCUSA as the minimum randomised offset limit?							
Respondent type	**210 secs**	**420 secs**	**600 secs**	**Analysis required**	**No minimum**	**No preference**	**Total**
DNO		1	3	1	1		6
Supplier	1		3				4
IDNO						1	1
Total	1	1	6	1	1	1	11

5.32 The Working Group noted the majority preference for 600 seconds. It was observed that if the value is found not to be appropriate in future then it can be adjusted by means of the DCUSA change process if it is deemed necessary.

5.33 The Working Group noted that they have sought to set the randomisation value at the optimum amount based on the information they have available at present. This has been based on industry consultation, including consultation with the System Operator.

Question 8 - Do you think there may be more Load Managed Areas in the future, potentially due to the increased connection of low carbon technologies? Are the proposed changes to the legal text sufficient to manage any associated issues that may arise?

5.34 The Working Group noted that all respondents expect that there is a possibility that there will be more LMAs in the future. It was noted that there was also a common thread that this is a difficult area to predict.

5.35 One respondent highlighted that there is the "*potential for Schedule 8 to be interpreted* *such that a company only ever requires one per licence area i.e. it just adds or removes post codes & times of day to the single LMA as and when required*." The Working Group noted that postcodes may not be unique to a distribution area, however, LMA notices are issued by the Distributor and the first two digits of the MPAN indicate which Distributor area the meter sits. The group developed a template for use by Distributors when notifying Suppliers of LMAs; more information on this is provided in section 6 below. The Working Group noted that Suppliers wish to have more communications from Distributors. Ofgem has oversight of network planning and emerging LMAs.

5.36 Another respondent highlighted that in the future there may be generation managed areas too. The group agreed that this was out of scope for DCP 204.

Question 9 – Would you see value in creating a central register of Load Managed Areas e.g. on the DCUSA website?

5.37 The following table provides a summary of the responses to this question.

Would you see value in creating a central register of Load Managed Areas e.g. on the DCUSA website?				
Respondent type	**Yes**	**No**	**Unsure**	**Total**
DNO	2	1	5.38 3	5.39 **6**
Supplier	4		5.40	5.41 **4**
IDNO	1		5.42	5.43 **1**
Total	**7**	**1**	5.44 **3**	5.45 **11**

5.46 The Working Group observed that the best location for this information would depend of the type of information required. For example, two Suppliers suggested that if the individual sites are identified then this information could be included in the Electricity Central Online Enquire Service.

5.47 The Working Group agreed that MPAN data should be circulated via email using a defined template. This template is provided as Attachment 5. The Group notes that the future preferred option is to have a requirement to identify MPANs associated with LMAs within centralised registration systems as part of Ofgem's proposed new target operating model, under which registration systems would be moved to the DCC. The group considers this to be a more cost effective approach than making any changes to the registration systems at present. The current proposal is to have the new centralised registration system in place by 2019; this timescale has been determined by Ofgem in their next day switching consultation. As a consequence of the latest Target Operating Model, this requirement will be discussed as part of Ofgem's Switching Programme.

5.48 The group noted that when there is a central register then the Supplier could do a pre-registration check to ensure that a customer is not moved on to the wrong tariff and to prevent erroneous transfers.

5.49 It was highlighted that the group had previously discussed including within the register information on why it is a LMA and an indication of when this is expected to end.

Question 10 – Do you agree that Provisional SRNs should be replaced by an advisory notice as proposed by the Working Group? An alternative would be that no notice is issued at this stage, what is your preference?

5.50 The Working Group noted that the majority of respondents to this question agreed with the use of an advisory notice. In response to one consultation respondent's comments, the Working Group agreed that the purpose of the advisory notice should be explained further in the Change Report; this information is provided in section 5 below.

Question 11 – Do specific considerations for new connections need to be included in Schedule 8? If yes, what additions are required?

5.51 The Working Group noted that eight of the eleven respondents did not believe specific considerations for new connections need to be included in Schedule 8.

5.52 The group noted that if you are looking at taking on a new connection, if it is a significant load then it is likely to trigger a network reinforcement. The Working Group agreed that this was outside of the scope of DCP 204 and would need to be addressed under a future CP. It was noted that any DCUSA Party can raise a CP.

<u>Question 12 – Should the definition of Capacity Headroom remain as "a margin of 15% below the maximum capacity of the Distribution System supplying a group of Customers"? If not, what should it be and why?</u>

5.53 The Working Group noted that there was a split between Distributors and Suppliers in the responses to this question. It was recognised by the group that Suppliers desire consistency and assurance that Distributors will not create an increasing number of LMAs and thus would like a defined Capacity Headroom. Counter to this it was noted that removing the 15% would potentially reduce the number of LMAs.

5.54 The Working Group agreed to amend the definition of Capacity Headroom to read as follows:

"means the minimum margin below the maximum capacity of the Distribution System which the Company reasonably believes is necessary and justifiable to maintain Security of Supply and other technical parameters. "

<u>Question 13 – Should there be a limit on the frequency at which network operators can request Suppliers to change load switching times?</u>

5.55 The Working Group noted that views were split between Suppliers and Distributors.

<u>Should there be a limit on the frequency at which network operators can request Suppliers to change load switching times?</u>				
Respondent type	**Yes**	**No**	**No View/ Undecided**	**Total**
DNO		5	1	**6**
Supplier	4			**4**
IDNO			1	**1**

Total	**4**	**5**	**2**	**11**

5.56 After discussing the consultation responses, the group agreed not to include a limit within the legal text. It was noted that Distributors, with Ofgem's oversight, would seek to keep them to a minimum.

Question 14 – In paragraph 6.4 of the legal text is 20 working days an appropriate amount of time? If not, what should this period be?

5.57 The Working Group noted that the majority of respondents agreed with the 20 Working Day value. The Working Group, therefore, agreed to keep this value in the legal text.

Question 15 – Are you supportive of the proposed implementation date of 1 April 2015? If no, please propose an alternate date and explain your rationale.

5.58 The Working Group noted that the majority of respondents agreed with the proposed implementation date of 1 April 2015.

5.59 It was noted that there are issues around randomisation and direct switching that cannot happen until SMETS2 comes into effect.

5.60 Following the close of the DCP 204 consultation, the DCC go-live date was moved backwards. The Working Group also recognised that Distributors and Suppliers need time to prepare for the implementation of DCP 204. It was therefore decided that the proposed implementation date for DCP 204 should be 1 April 2016.

Question 16 – Are there any additional smart meter related technical, operational or governance issues that need to be considered by the Working Group (in the context of load switching and time switching of smart meters)? If yes, please provide additional information.

5.61 The Working Group noted one respondent's concern that currently the Distributor is involved in the process of defining switching times through the application of Standard Settlement Configuration (SSC) rules under the BSC. Once Settlement moves to Half Hourly, SSCs will no longer be in existence and the Distributor will not be involved. The Working Group noted that the removal of SSCs will not be for several years and is therefore not an immediate issue; however, it may be a future unintended consequence of moving to HH settlement. The Working Group suggest that the industry and Ofgem consider this issue at the appropriate time as failure to consider this issue may increase costs to customers in the form of increased network reinforcement. The Working Group noted that the legal text includes a provision for early notice of potential LMAs which will help in these situations.

5.62 Another respondent raised a concern around confidentiality that prevents the Supplier from sharing information with the customer. As a consequence the Working Group reviewed and updated the confidentiality clause in Schedule 8.

Question 17 –Are there any specific issues that need to be considered relating to the withdrawal of existing services/ technologies, i.e. RTS, Cyclo Control etc. If yes, please provide additional information.

5.63 One respondent to this question noted that they did not believe there are any discussions happening at present to discuss replacement of the current functionality offered by the RTS. In response, the Working Group noted that DCP 204 is not a like for like change with the current arrangements. The Working Group does not wish to restrict new technology to the old processes and thus is intentionally developing a change that is not like for like. This issue is outside of the scope of DCP 204 and has been referred to the DCUSA Standing Issues Group (SIG) for further discussion, as DIF 045.

5.64 Another respondent suggested that it would be prudent for Suppliers to publish Load Switching Regimes with a minimum notice period such that the Distributors may assess the impact of the application of such regimes to all or some of the relevant customer's consumption. The respondent further explained that this comment is in relation to the withdrawal of old tariffs.

5.65 The group discussed whether Suppliers should inform Distributors of new products that focus on a certain area and provide the Distributor with information on what the switching times are and whether there would be scope to stagger the switching times. It was noted that Suppliers are likely to want to keep this information confidential until it is launched. A Working Group member highlighted that Distributors are required to approve Market Domain Data changes and thus would receive notice through this route, however, when the current arrangements are replaced by Half Hourly settlement this information will not be known. Consideration therefore will need to be given to this area in the future when Half Hourly settlement is introduced (see 5.51).

5.66 One Working Group member flagged that Suppliers will need a managed approach for closing the RTS system down, including a plan for those customers that will not have smart metering WAN. The Working Group noted that such a process would need to be agreed, however, it was outside of the scope of DCP 204.

Question 18 – Sections 5.3, 6.3 and 7.3 of the legal text detail the information that should be provided by a DNO issuing Notices. Is this information sufficient, if not what additional information is required?

5.67 The following table summarises the responses to this question.

Sections 5.3, 6.3 and 7.3 of the legal text detail the information that should be provided by a DNO issuing Notices. Is this information sufficient, if not what additional information is required?						
Respondent type	**Yes, this is sufficient**	**No, MPAN information needed too**	**No, information on applicable week days needed too**	**Other**	**No comment**	**Total**
DNO	4		1	1		**6**
Supplier	2	2				**4**
IDNO					1	**1**
Total	**6**	**2**	**1**	**1**	**1**	**11**

5.68 It was observed that the majority of respondents that felt that the information was sufficient were Distributors.

5.69 The Working Group noted that the majority of existing LMAs are driven by issues with Extra High Voltage network issues, and currently the Distributor would give postcode outcode rather than individual postcode.

5.70 It was observed that the easiest way of matching the notice to specific customers is for the information to be provided on an MPAN level. The group noted that there were reservations about providing this more granular data, as new customers would not be in the MPAN list until the point at which they are registered. As a halfway point it was suggested that there could be a list of MPANs provided to each registered Supplier from the Distributor, updated once every three months. This would mean that there would be a small number of newly registered customers that would not be on the list for a maximum of three months. The only alternative, if MPAN data is to be provided, would be to notify every time a new customer is added.

5.71 The group reached a consensus that MPAN level data should be provided. There will be one list, rather than a list per Supplier.

Question 19 – The Working Group considers that an adequate level of detail to summarise the nature of any Load Managed Area would be: Date Notified, postcode District/out-code (e.g. LS3) and Indicative End Date (if known) do you agree?

5.72 The following table provides a summary of the responses to this question

The Working Group considers that an adequate level of detail to summarise the nature of any Load Managed Area would be: Date Notified, postcode District/out-code (e.g. LS3) and Indicative End Date (if known) do you agree?						
Respondent type	**Agree**	**Agree but Provide MPAN too**	**Agree but Provide reason too**	**Agree but without end date**	**Unsure**	**Total**
DNO	3	1		2		**6**
Supplier	1	1	1		1	**4**

IDNO					1	**1**
Total	**4**	**2**	**1**	**2**	**2**	**11**

5.73 The Working Group has prepared a template that would be used by Distributors to provide information on LMAs in a defined file format. This template is provided as Attachment 5.

5.74 **Question 20 – Should there be standard templates for:**

- Load Managed Area Notices

- Security Restriction Notices

- Emergency Security Restriction Notices

If yes, should this be in DCUSA schedule 8?

5.75 The Working Group noted that all respondents to this question except for one agreed that there should be standard templates. The majority also agreed that the templates should be in DCUSA Schedule 8.

5.76 The sole respondent to disagree with the use of defined templates suggested that having templates within the DCUSA increases the administrative burden of DCUSA should they need to be amended.

Question 21 – Section 11 of the legal text places an obligation on DNO's to review LMA, SRN and Emergency SRN notices every six months, is this period appropriate? If not can you please provide an alternative period and explain your rationale.

5.77 The following table provides a summary of the views expressed in response to this question:

Section 11 of the legal text places an obligation on DNO's to review LMA, SRN and Emergency SRN notices every six months, is this period appropriate?

Respondent type	Agree with reviewing every six months	Disagree – reviews should be more frequent than every six months	Disagree – reviews should be annual	No comment	Total
DNO	2	1	3		**6**
Supplier	3	1			**4**
IDNO				1	**1**
Total	**5**	**2**	**3**	**1**	**11**

5.78 The Working Group discussed the comments received in response to Question 21 and agreed that where a notice is revoked the Distributor should not wait for the six month review period before notifying Suppliers. It was noted that this is captured within the current version of the DCUSA legal text. The group agreed that wording should be included within the DCP 204 legal text saying that where a constraint is removed notice should be given, i.e. do not wait for the six month review.

5.79 Following the review of the consultation responses, the Working Group updated section 12 of the legal text to provide a compromise position in that the review periods are set as follows:

- Advisory Notice and LMA Notice - every 12 months
- SRN and Emergency SRN - every six months
- Compliance Notice - every three months

Question 22 – It is proposed that reference to SSCs is removed in the legal text and has been replaced by reference to Load Switching and Load Switching Regimes. Do you agree with these changes, if not please provide your rationale.

5.80 Following the review of consultation responses, the Working Group agreed that reference

SSC should remain as part of the definition of "Load Switching Regime". It was also subsequently agreed that a definition of "Load Switching" was not required.

Question 23 – Do you have any other comments on the proposed legal text?

5.81 The Working Group reviewed the comments on the legal text and agreed to make a number of amendments to the text. The finalised version of the legal text is provided as Attachment 1.

5.82 It should be noted that amendments to the legal text mean that the paragraph numbers referenced by consultation respondents (in Attachment 4) may not line up with the paragraph numbering in the final version of the legal text.

Question 24 – Are there any alternative solutions or matters that should be considered within the Change Proposal?

5.83 The majority of respondents to the consultation did not identify any alternative solutions or matters.

5.84 The Working Group noted that in response to this question one Supplier respondent reiterated their caution on ensuring that the CP does not result in a reallocation of costs from Distributors to Suppliers.

5.85 Another respondent suggested that demand control would better sit under the Distribution Code. The Working Group noted the respondent's view.

5.86 A Distributor respondent stated that:

5.87 *"We consider that some risks may arise in the near future with smart appliances that migrate their consumption to times of low electricity cost. It is not clear at this time to what extent the Supplier will be in control of such smart appliance behaviour, downstream of the meter, or whether control is limited to the variability in any pricing signals conveyed by the Supplier."*

5.88 The Working Group noted the respondent's comments and noted that DCP 204 had been raised to bring Schedule 8 up to date in a world without radio teleswitching. It was subsequently identified that Suppliers are changing their customer offerings as they move towards a smart world that may require future changes to DCUSA and the Balancing and Settlement Code (BSC). It was agreed that much of the changes needed to accommodate the move to smart metering sit outside the scope of DCP 204.

Question 25 (DNOs/IDNOs only) – Do Load Managed Areas currently exist on your network, and where are they located?

5.89 The Working Group noted that no Independent Distribution Network Operators (IDNOs) currently have LMAs. The following four Distribution Network Operators (DNOs) currently have LMAs:

- WPD
- SSEPD
- UKPN
- SP Distribution/SP Manweb

5.90 Details of these LMAs are provided as Attachment 6.

Question 26 (DNOs/IDNOs only) – What additional obligations does there need to be within Schedule 8 of DCUSA to notify other distributors that are associated or may become associated with Load Managed Areas and the other distributor obligations to notify Suppliers connected to their network?

5.91 The Working Group noted that one respondent to this question suggested that:

"There may be third party networks (IDNO or private) which have embedded generation connected to them such generation could impact on the need and requirements for demand restriction notices on both the 3rd party network and the upstream DNO network."

5.92 The Working Group discussed this comment and noted that IDNOs are required to notify DNOs of embedded generation, so that this can be factored into Capacity Headroom calculations. The group agreed that no changes are required to the DCUSA to further accommodate this area.

Question 27 (DNOs/IDNOs only) – How often are emergency SRNs used?

5.93 The Working Group noted that respondents indicated that emergency SRNs are used infrequently, with some respondents saying they are never used and others saying they are used rarely.

5.94 One respondent suggested that they may become more frequently used in the future.

Question 28 (Suppliers only) – Are you aware of the existence of load managed areas and do you understand where they are located?

5.95 The Working Group noted that Supplier respondents were generally not aware of the existence of any LMAs. The group noted that increased awareness is therefore required of LMAs across the industry.

5.96 It was observed that DCP 204 may act to highlight the existence of LMAs and improve dialogue between Suppliers and Distributors regarding this issue. The fact that Suppliers will now receive lists of LMAs and affected MPANs will also make these processes more visible.

5.97 The Working Group also noted that as part of the process Distributors will be reviewing load on their networks, which may require Distributors to engage with Suppliers if they believe that the rules are not being followed.

Question 29 (Suppliers only) – What would a supplier do when they get an advisory notice?

5.98 Three respondents to this question noted the need for Suppliers and Distributors to work collaboratively to resolve the issue. Another respondent explained that they were unable to comment on a specific process.

5.99 The Working Group noted that discussion groups could be established to facilitate the flow of information between Suppliers and Distributors as specific network issues arise.

<u>Question 30 (Suppliers only) – When do suppliers expect to commence removing existing equipment that directly controls customers load and replacing it with smart meters? Are there any specific issues relating to “timing” that need to be considered in the development of this proposal?</u>

5.100 The Working Group noted that the majority of respondents indicated that this would commence only once SMETS 2 compliant metering becomes available.

<u>Question 31 (DCC only)– What information will you need from DNO’s regarding the location of Load Managed Areas to enable you and your service providers, especially the communications service providers, to ensure that there is adequate WAN provision in the locations affected?</u>

5.101 The Working Group noted that the DCC would like postcode level information, which ties in with the discussions of the DCP 204 Working Group.

<u>Question 32 (DCC only)– How soon will it be known where enduring areas of no WAN will be? How will this information be provided to DCC Users and other interested industry parties?</u>

5.102 In response to this question, the DCC provided the following information:

“DCC is planning to publish coverage data during August that will set out by full postcode, for each Communications Service Provider (CSP) Region, where coverage will be available either at the end of 2015, between 2016 and 2020 or where areas may potentially fall into an enduring area of no SMWAN. The data published at this point will be 90% accurate with this accuracy being progressively improved on a quarterly basis until the start of Smart Meter roll-out.

More info on enduring ‘no WAN’ is provided in the DCC Statement of Service Exemptions, currently being consulted on here:

https://www.gov.uk/government/consultations/dcc-procurement-strategy-and-statement-of-service-exemptions“

5.103 Since providing the above response, the Working Group notes that the DCC has published initial coverage guidance. This cannot be circulated with the DCP 204 change report as it has been published with a confidentiality clause.

5.104 A DCP 204 Working Group member highlighted that a significant number of the permanent no WAN areas are located in the north of Scotland.

6 ADDITIONAL FEEDBACK~~SSESSMENT AGAINST THE DCUSA OBJECTIVES~~

Comment [RT3]: Check heading and numbering.

7.1 Following the close of the first industry consultation, the DCP 204 Working Group received additional feedback from Citizens Advice and National Grid.

Citizens Advice Feedback

7.2 Citizens Advice noted their support for the general approach of translating the provisions in schedule 8 to apply to smart metering.

7.3 With regards to the requirement for Randomised Offsets, Citizens Advice expressed concerns that this could disrupt consumers' ability to rely on a schedule. If, for example, a consumer was to delay their washing until 10 o'clock how would they know that they wouldn't end up in the higher price band by accident if randomised? In response, the Working Group noted that this issue already exists under the current arrangements for randomisation and is not a new issue introduced by DCP 204. The group noted that the application of tariffs is the responsibility of the Supplier.

National Grid Feedback

7.4 In their feedback, National Grid stated that they were reasonably happy that, on the grounds that the CP is a straightforward technology switch that seeks to as a minimum to retain the same functionality, there is no tangible impact.

7.5 National Grid also requested confirmation that there will be sufficient randomisation built in to the switching to avoid spikes. The Working Group discussed this comment and noted that DCP 204 seeks to replicate the current RTS arrangements as best it can, thus the choice to set the randomised offset limit to a value of no less than 600 seconds. It was noted that if 600 seconds is found not to work, then signals can be sent to the meters to vary this randomisation.

7.6 The group also noted that the roll out of smart meters will be over several years, meaning that there will be a gradual move away from RTS rather than a sudden one.

8 POST CONSULTATION DISCUSSION TOPICS

Comment [RT4]: Numbering

9.1 Following the close of the first consultation, the Working Group discussed the CP further in the following areas.

9.2 **New Connections**

9.3 The current arrangements only apply to existing connections. DCP 204 does not cater for managing new connections. The CP seeks only to replicate the existing arrangements and as such this topic was deemed to be out of scope. The Working Group notes that any DCUSA Party may raise a CP to address this area.

9.4 **New Load Switching Regimes**

9.5 The Working Group has not included any provisions within the DCP 204 legal text for the creation of new Load Switching Regimes. This is because this area is already covered off under the Balancing and Settlement Code (BSC) processes around creating new SSCs.

9.6 **Supplier Engagement**

9.7 It was observed that only four Suppliers had responded to the DCP 204 consultation. All Suppliers will need to understand the implications of DCP 204 on their systems and processes. It was noted that Suppliers will have an opportunity to comment again on the CP as part of their voting response.

9.8 The Working Group noted that should DCP 204 be implemented, it will create an opportunity for Distributors to communicate the importance of demand control as Distributors will be circulating information on demand controlled areas as part of the requirements of the CP.

9.9 It was noted that it may be sensible for a Smart Metering Installation Code of Practice (SMICoP) change request to be raised, to make sure that before a meter exchange is carried that the customer’s heating and switching requirements are left on an appropriate arrangement. The group noted that this is outside of the scope of DCP 204 and would be for a SMICoP party to raise. A Working Group member raised this issue at the SMICoP Governance Board (SGB) meeting on 27 November. The SBG agreed that this area may need to be considered by SMICoP in the future.

9.10 **Information Required by Suppliers**

9.11 The Working Group developed a notification template for use by Distributors in providing information to Suppliers. This will ensure that such information is provided in a consistent format. There are two elements to the notification template, namely:

- A spreadsheet that provides an overview of all LMAs, SRNs and Emergency SRNs
- A separate CSV file in which all affected MPANs will be listed. This CSV file is intended to make it possible for Suppliers to load the MPAN information in to their systems.

9.12 The reason why MPAN data is provided in a separate CSV file is that there is the potential for the number of affected MPANs to exceed the number that could be held within an excel spreadsheet.

9.13 The spreadsheet template, which includes guidance on the production of the CSV file, is provided as Attachment 5. The CSV file and spreadsheet will be issued to all Suppliers, not just those Suppliers with affected MPANs. The Working Group considered whether there would be any confidentially issues with the provision of MPAN level data to all Suppliers and concluded that there are no such issues. It is noted that lists of MPANs are already circulated for other reasons under the provisions of another industry code.

9.14 The Working Group also discussed incorporating the notification information into central registration systems. Working Group members agreed that there would be merit in this suggestion in the longer term. However, given Ofgem's recent decision that registration systems will come into the DCC in due course, it was the view of the Working Group that now would not be an appropriate time to progress changes to registration systems. It was also noted that Distributors that do not have any LMA areas would need to make changes to their registration systems for no benefit if a change were progressed at present.

9.15 **Capacity Headroom**

9.16 The Working Group noted that Capacity Headroom defines when a LMA should be triggered. The Distributor uses LMAs to not only manage load but also security of supply and statutory requirements, such as voltage. It was observed that the use of LMAs has to be balanced against not constraining customers' network usage unnecessarily.

9.17 With regards to Capacity Headroom, it was highlighted that it is in the Supplier's interest to get as close to the network capacity a possible before declaring a LMA. To facilitate this, the Working Group agreed that rather than defining Capacity Headroom as a fixed value the DCP 204 legal text should instead permit Distributors to determine an appropriate value is believed to be necessary and justifiable to maintain Security of Supply and other technical parameters.

9.18 **Demand Aggregators**

9.19 The Working Group questioned whether Short Term Operating Reserve (STOR) is a load switching programme. The group agreed that this was outside the scope of DCP 204.

9.20 It was noted that the actions of Demand Aggregators, when responding to price signals, may have the effect of creating a need for a LMA through their actions. The Working Group noted that as Demand Aggregators are not Parties to DCUSA this is not something that DCP 204 can address.

9.21 **The Advisory Note**

9.22 The purpose of an advisory notice is to enable a Distributor to advise Suppliers operating within its area that there is a risk that at a specific location that a LMA notice may be issued unless there is a change to the way load is managed with the area in question. The notice would act as a catalyst for Suppliers and the Distributor to discuss ways of managing load.

9.23 The Working Group notes that the intent is to prevent an LMA notice being issued.

9.24 **Conflicting Drivers**

9.25 The Working Group notes that there may be a conflict between deriving benefit directly from smart meters versus the way Distributors are being regulated in RIIO-ED1 to minimise or defer network reinforcement using technologies that are available to them.

9.26 **"Users" and "Suppliers" in DCUSA**

9.27 The Working Group notes that within Schedule 8 the terms "User" and "Supplier" are both utilised. Based on the definitions of User and Supplier within the DCUSA these terms have the following meanings within Schedule 8:

- A "User" is actually operating in an LMA (i.e. is responsible for an MPAN in an affected area) and may need to take action; and
- A "Supplier" may go into an LMA and at that point may need to take some action.

9.28 **Replicating Time Switching and Load Switching in the Smart Roll-out**

9.29 During the progression of DCP 204, the Working Group identified that the existing time-switching and load switching arrangements depend on data items such as Group Codes, Standard Settlement Configurations (SSCs) and Time Pattern Regimes (TPRs). These data items and processes ensure the replication of time-switching arrangements through meter change and/or change of supplier events.

9.30 These data items exist in non-half hourly settlement, but will not be available for use in respect of customers migrating to half-hourly settlement. This could mean that under the Smart arrangements, customers' heating and switching requirements may not be left on an appropriate arrangement.

9.31 The Working Group asked the Standing Issues Group (SIG) to consider which industry Code this matter should be addressed under. It was raised as SIG Issue (DIF) 045 'Replicating Time Switching and Load Switching in the Smart Roll-Out'.

9.32 After consulting with Elexon, Ofgem and the Cross Codes Forum, it was the recommendation of the SIG that this issue best sits under the DCUSA as it is the only industry Code that covers the obligations between DNOs and Suppliers.

9.33 It was observed that the issue could potentially be considered within the scope of DCP 204, however, it was agreed that the issue should be addressed under a separate change.

The reasoning for this includes:

- When the DCP 204 Working Group was formed it was not envisaged that the change would incorporate replicating time switching and load switching arrangements, meaning that those with an interest in this area would not have realised that it was to be discussed when the Working Group invitation was issued.

- Incorporating these areas within DCP 204 increases the risk that there will be elements of the CP that Parties do not agree with, increasing the risk of the CP being rejected.

9.34 The Working Group recommends that once the outcome of DCP 204 is known, a CP be raised regarding replicating time switching and load switching in the smart roll-out. Schedule 8 as amended by DCP 204 will then form the baseline legal text for this new CP. It is noted that any Party to DCUSA may raise a change to the Code.

9.35 **Why Do Load Managed Areas Exist**

9.36 The Working Group notes that load switching arrangements are required to minimise distribution infrastructure and associated investment. In some areas the electrification of much of the distribution network was carried out on a minimum economic cost basis, with light network infrastructure and lesser standards of security of supply to that in the rest of the UK. This meant, for example, that many networks were unsecured, and/or were reliant on diversified restricted load switching arrangements.

9.37 In certain Distributor areas, this is economically critical for minimising high cost reinforcements that would only benefit a relatively low number of customers and maintaining a reasonable level of Use of System charges on sparse distribution networks. It is particularly important to maintain this diversity in load switching patterns in rural areas, and in those parts of the network which may be supplied on a temporary basis by standby diesel power stations, as this provides important reductions in peak demand, and associated plant power requirements. Any reduction in this diversification would be likely to lead to either significantly increased costs, or loss of supply (during planned or unplanned outages) or both.

10 OFGEM SEND BACK LETTER DISCUSSIONS

11.1 On 19th June 2015 Ofgem issued a letter of direction to the DCUSA Panel regarding DCP204 'Smart Metering Related Amendments to Schedule 8' (Attachment 8). Ofgem indicated that they could not form an opinion based on the Change Report and Change Declaration. They identified areas where further information was required, stating that the Change Report should:

1. Indicate the costs and benefits of continuing the existing regime through smart meters in the proposed manner. The Change Report should indicate how consumers will be better off with this proposal.

2. Present the benefits and reasons for rolling out the randomisation functionality to all smart meters as opposed to just those in LMAs.

3. Justify and describe the benefits of having a minimum randomisation offset limit of 600 seconds (10 minutes) as opposed to another limit.

4. Describe how customer confusion from randomised switching times can be avoided. This should be backed up with information on the potential benefits to consumers through these new arrangements, for example the potential for better information for customers.

11.2 The Working Group was re-convened to discuss each of the above concerns. Details on the Working Group's discussions are provided below.

Cost Benefits

11.3 With regards to the cost benefits of the CP, the Working Group considered whether it was appropriate or possible to undertake a full cost benefit analysis exercise. The group noted that DCP 204 is not creating a new process, but rather making the current process more efficient, easier to manage and making it smart meter ready.

11.4 The group agreed that it would not be feasible to carry out a full cost benefit analysis, however, each individual cost and benefit was discussed and where it was possible to quantify it the group sought to do this. The following two tables provide details on this analysis.

Benefits	**Can it be valued?**	**Value**
Avoiding Distribution Network Reinforcement The CP will ensure that Schedule 8 remains suitable under smart metering, thus it will continue to enable Distributors to avoid distribution network reinforcement by: • maintaining diversity in switching times; and • maintaining randomised offset Note: Distribution network reinforcement would be required to manage thermal and/ or voltage related issues.	Yes, avoided reinforcement costs can be calculated.	Avoided reinforcement costs for SHEPD: £161million to £718 million
Grid Benefits National Grid benefits from Schedule 8 remaining suitable under smart metering in the following areas: • Balancing services; • frequency management; and • minimisation of voltage step change issues associated with simultaneous switching of material load	National Grid Response: "Very difficult to place a value on this. The inclusion of randomisation though counteracts the increased volatility that would otherwise result from smart metering by smoothing out demand changes and reducing the risk of frequency spikes. Without randomisation there will be further costs to consumers associated with frequency management or holding of additional reserves."	National Grid Response: "Based on a wholesale electricity price of £50/MWh, an annualised figure for additional reserve holding could be estimated at £450k pa per MW representing the costs of curtailment, out of merit running or additional ancillary services. While difficult to quantify the impact exactly, it is easy to see that even a small change in reserve holding (say 10-20MW) has a large financial consequence."
Consistency in randomised time	The working group does	Marginal benefit for

Comment [RT5]: Are other DNOs that operate load managed areas able to provide a view on this one too? What are your avoided reinforcement costs that come from continuing to operate under schedule 8?

ACTION: DNOs

Comment [RT6]: 7 Sept: Email DNOs with LMAs to ask if they can provide information for inclusion in the change report then follow up with phone call. ACTION: ELECTRALINK

switching Currently there is planned offset and unplanned offset[4]. DCP 204 will introduce consistency that will enable the customer to be informed of what the bandwidth on the time switch will be. It is noted that the Supplier approach to communicating randomised offset to their customers will not be prescribed as part of DCP 204.	not see their being a direct quantifiable value for this benefit.	Suppliers by having a uniform message Having a consistent approach will ensure fairness and equality across Suppliers, i.e. it will not advantage or disadvantage any particular customers.
EU Third Package: Optimisation of the Use of Electricity The EU third package legislation requires optimisation in the use of electricity. DCP 204 will confirm the demand control areas to minimise coincidence of load (which would be lost under the migration to smart if DCP 204 is not implemented) thus optimising energy use.	As it is legislation a costed value is not required	n/a
Increased Transparency The CP provides clarity and transparency around existing obligations (e.g. not changing the SSC is in the existing Schedule 8)	The Working Group believe that it is not practical to allocate a financial value to this benefit	n/a
Improved Information Provision The CP helps Suppliers to identify customers in load managed areas, i.e. it improves the ability to comply with existing Schedule 8 provisions by providing appropriate information in an electronic format[5].	The Working Group believe that it is not practical to allocate a financial value to this benefit	n/a

4 Unplanned offset is a consequence of the inaccuracy of time keeping associated with traditional programmable meters and electro mechanical time switches

5 It is noted that the group agreed that in the future customer data should be incorporated in to registration systems

Risk Management The CP removes the risk that the Supplier could switch all of their load to come on at a single time without notifying the Distributor (it is noted that with Smart meters, Suppliers will have the ability to change switching times remotely) It is noted that both Distributors and National Grid will benefit from this.	The Working Group does not believe that it is feasible to cost this benefit	n/a

Costs	Costable?	Value
Setting Meters Up The CP requires that Suppliers ensure that smart meters are programmed with randomised offset. It is noted that the randomised offset facility is already a requirement under SMETS2, thus the DECC programme has facilitated this feature within SMETS2, including within the DCC user services.	Suppliers have to put a randomisation value in to their smart meters, the cost of doing this in line with the 600 seconds required by DCP 204 is negligible.	n/a
Communicating to Customers Suppliers will incur administrative costs around communicating the offset approach to customers and responding to queries on it. This is because the switching times will be more visible to customers than at present. It is noted that the Offset value will be presented over the HAN on the In home Display and any Customer Access Devices (CADs).	It is recognised that there are significant planned communications to customers regarding smart meters. Communicating on switching times will form a small part of this (it is noted that around 20% of customers have multi-rate tariffs)	Marginal cost in updating planned communications to incorporate switching information There will be a capability to provide updates to in energy home management systems.
Provision of granular data Under DCP 204, Network		Negligible

Operators will be required to provide more granular level data to Suppliers		

Rolling Out Randomisation to All Meters

11.5 The Working Group recognise that without the application of rules relating to randomisation, the introduction of smart meters can be expected to have a tendency to synchronise load around tariff switching and/or load switching times.

11.6 Customers who are presently supplied via multi rate tariffs already take advantage of cheaper rates by aligning “higher consuming” elements of their load to the cheaper rate(s) of the particular tariff. The incidence of this is likely to increase in future as customers adopt new low carbon technologies for transport and space/water heating (electric vehicles and heat pump technology). It also needs to be recognised that once greater amounts of data from smart meters is available to Suppliers there will higher levels of engagement leading to ‘smarter’, more engaged customers. The general cost of energy relative to incomes can be expected to drive the development and uptake of more complex, time of use (TOU) and ‘smart’ tariffs. The purpose of these tariffs is to influence customers to use more energy when rates are at their lowest, the application of a randomised offset to all meters will ensure that any associated load pick up can be managed at both a local (DNO) and national (TSO) level.

11.7 The introduction of smart meters will also provide options for indirectly connected load to be controlled via the home area network (HAN). The future availability of HAN connected auxiliary load control devices will provide customers (and suppliers) with the option for load that is located remotely from the smart meter to be controlled via the smart meter. The use of this technology is therefore likely to increase the coincidence of load to the extent that it will be necessary to apply a randomised offset to load switched in this way. Examples of technologies which may be switched via HAN connected devices include:

- Water heating;
- Space heating;
- Heat pumps;

- Electric vehicle charging;
- Smart laundry equipment; and
- Other equipment responding to a TOU price signal

11.8 Whilst there is uncertainty regarding how customers will control load (directly or indirectly from the smart meter) applying a common rule regarding the application of a randomised offset will ensure that:

- Load "pick up" is staggered no matter how it is controlled;
- Customers will know when the rate change occurs and hence be able to program their equipment appropriately;
- Suppliers have a common set of rules; and
- The message to customers from national bodies such as Smart Energy GB (SEGB) can be consistent.

11.9 There was significant support for the application of randomised offset to all meters in the consultation where 8 out of 11 respondents supported this position.

~~11.9~~ As Load Managed Areas would appear to be a designation determined by the DNOs and to not be uniform across all DNO areas then from a GBSO point of view I don't think that this is enough and the requirements for randomisation would need to be across all areas. The rationale for this is essentially the same as previously stated – if randomisation only applied within LMAs then the effectiveness of this would need considerably more work to determine whether it achieved randomisation to the correct extent."

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Comment [RT7]: Natianal Grid text to be added here.

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Minimum Randomised Offset Limit

11.10 The reasoning behind the need to apply a randomised offset is detailed in Attachment 3. This document describes why a randomised offset is required; noting that when establishing the basic off peak switching times and the associated randomisation there are a few principles that are relevant including:

- Distributors need to:
  - minimise voltage step change issues associated with simultaneous switching of material load; and
  - maximise network utilisation by staggering switching times to allow load switched on earlier to fall/drop off before switching on additional load
-
- National Grid/Generators needs a predictable load pick up without any material step changes
- Customers need to:
  - know the times when the off peak load is switched; and

    - have assurance that load switching coincides with tariff/ rate change (this is a requirement in SMETS)
-
- Suppliers/Elexon need to know the:
    - times when the off peak load is switched; and
    - total volume of load switched in each time period for supply volume allocation purposes

11.11 In Attachment 3 it is recommended that nominal switching times should be set on the hour or half-hour with a Random Offset Limit in the range 600 seconds to 1799 seconds. The DCP 204 Working Group consulted industry participants on their views regarding the value that should be defined in DCUSA as the minimum randomised offset limit. Based on the responses received it was agreed that the value should be set to 600 seconds (10 minutes).

11.12 The Working Group notes that randomisation is currently deliberately and “accidentally” applied to tariff rate and/or load switching. A number of technologies are used to change tariff rates and switch load, including:

- Radio Teleswitch System (RTS);
- Programmable meters (RTC – real time clock); and
- Time switches.

11.13 Additional information on these sources of randomisation is provided in Appendix A.

11.14 In considering the randomisation effect of existing metering systems it can be observed that the minimum period of randomised offset currently applied is 7 mins (420 seconds). Given that significant numbers of meters switch with an unknown but longer randomisation period it was felt by the Working Group that 10 minutes (600 seconds) provides a pragmatic alternative. It is noted that DECC has agreed the need for a randomised offset, with Network Operators and National Grid to determine the initial value based on discussions with Suppliers. It is also noted that the 600 seconds can be amended in the future via a DCUSA Change Proposal if it is found that an alternative value would be preferable. SMETS2 provides capabilities and functionality to enable the offset to be changed in the future as may be required, by remote messaging to the meters.

11.15 It should be recognised that the majority of the Working Group voted in favour the randomised offset limit being set at 600 seconds. It is also noted that the message to customers regarding randomised offset may be easier for Suppliers by using 10 minutes rather 7 minutes.

11.16 A single configuration of randomised offset limit for all smart meters should simplify the management of this issue by suppliers on an enduring basis. Having a single “national” randomised offset limit built into all smart meters will enable suppliers to:

- specify a single configuration when they procure meters from manufacturers; and
- be aware of the offset limit applied to a meter when they gain a customer through the change of supplier process.

Randomised Offset – Keeping Customers Informed

11.17 Customers served by traditional metering systems using the technologies detailed above may not currently know the exact switching times associated with their chosen tariff.

11.18 The description by suppliers to customers of tariffs that offer different rates at different times of day are often flexible, e.g. (for Economy 7) there will be a low rate applied for a period of 7 hours overnight.

11.19 It can be observed that Suppliers choose not to explain randomisation to customers but state that times may vary, however, they also confirm that the customer will receive a specified number of hours at the cheaper rate.

11.20 There are a number of reasons why the times differ however for this change proposal it needs to be recognised that communicating different switching time information to customers is normal industry practice. Furthermore, all industry participants are increasing their engagement with customers and putting ever greater effort into communication, so there is nothing to suggest that this communication cannot be successfully achieved.

11.21 The deployment of smart meters and the functionality associated with tariff and load switching provides a significant improvement when compared with existing metering systems and associated arrangements.

11.22 Regarding tariff and load switching regimes the customer will be advised regarding when a tariff rate will change via the display or the consumer access device (CAD). Furthermore, given the accuracy of a SMETS2 meter (accurate to within 10 seconds of Coordinated Universal Time (UTC) date and time) once the meter has had the randomised offset limit configured a meter will retain the same randomisation period unless the supplier chooses to alter the configuration.

11.23 Having a nationally agreed randomisation period will enable delivery of a consistent message by the industry to customers who rely on multi rate tariffs. This could be undertaken by Smart Energy GB as part of its smart metering communications on behalf of suppliers.

11.24 The Working Group notes that customers who have SMETS2 meters may have access to presentation of their consumption profile at a granular level that will also help them to recognise the periods where energy is charged at a lower cost.

12 EU THIRD PACKAGE

13.1 The Working Group noted that DCP 204 supports EU Third Package Proposals and agrees with Ofgem that it is one of the most important pieces of legislation with the aim of further liberalising European energy markets. [6]

13.2 In the light of the dysfunction in the internal market in electricity, the European Commission considered it necessary to redefine the rules and measures applying to that market in order to guarantee fair competition and appropriate consumer protection. Directive 2009/72/EC of the European Parliament is aimed at introducing common rules for the generation, transmission, distribution and supply of electricity. It also lays down universal service obligations and consumer rights, and clarifies competition requirements.

13.3 Member States must designate distribution system operators or require undertakings that own or are responsible for distribution systems to do so. Distribution system operators are mainly responsible for[7]:

- ensuring long-term capacity of the system in terms of the distribution of electricity, operation, maintenance, development and environmental protection;
- ensuring transparency with respect to system users;
- providing system users with information;
- covering energy losses and maintaining reserve electricity capacity.

13.4 In particular, the group believe that the proposal supports Directive 2009/72/EC[8] by reference to particular clauses within the legislation as follows:

Article 2 - definitions

29. 'energy efficiency/demand-side management' means a global or integrated approach

[6] Sourced from: https://www.ofgem.gov.uk/electricity/transmission-networks/european-wide-initiatives/eu-legislation
[7] Sourced from: http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=URISERV:en0016
[8] http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2009:211:0055:0093:EN:PDF

aimed at influencing the amount and timing of electricity consumption in order to reduce primary energy consumption and peak loads by giving precedence to investments in energy efficiency measures, or other measures, such as interruptible supply contracts, over investments to increase generation capacity, if the former are the most effective and economical option, taking into account the positive environmental impact of reduced energy consumption and the security of supply and distribution cost aspects related to it;

Article 3 (Public service obligations and customer protection)

10. Member States ***shall implement measures*** *to achieve the objectives of social and* ***economic cohesion*** *and environmental protection,* ***which shall include energy efficiency/demand-side management measures*** *and means to combat climate change, and security of supply, where appropriate.* ***Such measures may include, in particular,*** *the provision of adequate economic incentives,* ***using, where appropriate, all existing national*** *and Community* ***tools****,* ***for the maintenance and construction of the necessary network infrastructure****, including interconnection capacity.*

11. In order to promote energy efficiency, Member States or, where a Member State has so provided, the regulatory authority shall strongly recommend that electricity undertakings ***optimise*** *the use of electricity, for example by providing energy management services, developing innovative pricing formulas, or introducing intelligent metering systems or smart grids, where appropriate.*

Article 4 - Monitoring of security of supply

Member States shall ensure the monitoring of security of supply issues. *Where Member States consider it appropriate, they may delegate that task to the regulatory authorities referred to in Article 35. Such monitoring shall, in particular, cover the balance of supply and demand on the national market, the level of expected future demand and envisaged additional capacity being planned or under construction, and the quality and level of maintenance of the networks****, as well as measures to cover peak demand*** *and to deal with shortfalls of one or more suppliers.*

Article 25 - Tasks of distribution system operators

*Clause1. **The distribution system operator shall be responsible for ensuring the long-term ability of the system to meet reasonable demands** for the distribution of electricity, for operating, maintaining and **developing under economic conditions a** secure, reliable and **efficient electricity distribution system** in its area with due regard for the environment and energy efficiency.*

Clause7. When planning the development of the distribution network, **energy efficiency/demand-side management measures** or distributed generation **that might supplant the need to upgrade or replace electricity capacity shall be considered by the distribution system operator.**

13.5 **The EU third package legislation includes a requirement that the use of electricity be optimised. DCP 204 will confirm the demand control areas and secure randomised offset of switching times to minimise coincidence of load and any peak demands around switching times (which would be lost under the migration to smart if DCP 204 is not implemented) thus optimising energy use, including around switching times**.

13.6 Under Directive 2009/72/EC Transmission system operators are mainly responsible for:

- ensuring the long-term ability of the system to meet demands for electricity;
- **ensuring adequate means to meet service obligations;**
- **contributing to security of supply;**
- managing electricity flows on the system;
- providing to the operator of any other system information related to the operation, development and interoperability of the interconnected system;
- **ensuring non-discrimination between system users;**
- providing system users with the information they need to access the system;
- collecting congestion rents and payments under the inter-transmission system operator compensation mechanism.

13.7 The Working Group notes that DCP 204 will support National Grid in meetings its obligations and specifically Article 12 of the directive states.

Article 12 (Tasks of transmission system operators)

Each transmission system operator shall be responsible for:

(a) ***ensuring the long-term ability of the system to meet reasonable demands for the transmission of electricity, operating, maintaining and developing under economic conditions*** *secure, reliable and* ***efficient transmission systems*** *with due regard to the environment;*

(b) ensuring adequate means to meet service obligations;

(c) contributing to security of supply through adequate transmission capacity and system reliability;

(d) managing electricity flows on the system, taking into account exchanges with other interconnected systems. To that end, ***the transmission system operator shall be responsible for ensuring*** *a secure, reliable and* ***efficient electricity system*** *and, in that context, for ensuring the availability of all necessary ancillary services, including those provided by demand response, insofar as such availability is independent from any other transmission system with which its system is interconnected;"*

14 SUPPLIER ENGAGEMENT

15.1 The Working Group noted that in its Send Back Letter (Attachment 8) Ofgem observed that all Suppliers will need to understand the implications of DCP204 and expressed concerns that Suppliers may not have engaged sufficiently with the CP.

15.2 During the progression of DCP 204 the Working Group has sought to engage with Suppliers. Following receipt of the Send Back Letter, the group took the following additional actions to encourage participation in the group:

- An invitation to join the DCP 204 Working Group was issued to all DCUSA Contract Managers, highlighting Ofgem concerns regarding Supplier engagement;
- Once a meeting of the DCP 204 Working Group had been scheduled to discuss the Send Back Letter, a further invitation was sent to DCUSA Contract Managers stating that additional participation, especially from Suppliers was welcome;

15.3 As no additional Supplier Members joined the Working Group, the group took the following additional steps to engage with Suppliers:

- The group issued a succinct consultation targeted towards small Suppliers. This document is provided as Attachment 9 and the responses received are detailed in section 10 below.

- A Question and Answer dial in session was held on 1 October 2015 to give Suppliers the opportunity to ask the Working Group any questions they might have on DCP 204. The intent of this session was to aid Suppliers in responding to the consultation document provided as Attachment 9. One Supplier dialled into the session.

- A representative from the group attended the Cornwall Energy Domestic Energy Supplier Forum on 9 September 2015 to present on DCP 204. The slides presented at this forum are provided as Attachment 10.

16 DCP 204 CONSULTATION TWO

17.1 On 17 September 2015, the Working Group issued a second consultation to market participants, which was designed to be targeted towards small Suppliers. There were 7 responses received, all of which were from larger Supplier companies and DNOs. This section summarises the responses received. The full set of consultation responses are provided as Attachment 9.

Question 1 - Do you have any comments on the DCP 204 legal text (Attachment 1)?

17.2 Three respondents had no comments on the legal text.

17.3 A Supplier respondent explained that they do not agree that the Randomised Offset Limit should be between 600 and 1799, noting that "*if we were requested to set the limit at 1799 we believe this would cause significant customer issues and confusion particularly with the introduction of more granular time of use tariffs. We believe the limit should be set at 600.*"

17.4 The Working Group discussed the respondent's concern and noted that 600 will give the minimum randomisation that is required, going up to 1799 is there to give Suppliers flexibility in their commercial offerings but it also means that in load managed areas (or where security restriction notices or emergency security restriction notices are issued) one of the actions there could be to increase the randomised offset limit as a means of mitigation. Having up to 1799 gives this flexibility (.i.e. there is a wider window available should Suppliers wish to use it).

17.5 Another Supplier respondent suggested that the DCP 204 the legal text should be reviewed with the purpose of ensuring the safeguards on declaring that Suppliers make changes to the Randomised Offset Limit are fit for purpose.

17.6 The Working Group discussed this comment and noted that Suppliers would like safeguards that would prevent them from receiving a large number of notices over a very short time period. In response, it was highlighted that the DCP 204 legal text states that under normal circumstances notices will not be issued within 20 Working Days of the last notice for that area.

17.7 The Working Group discussed whether 20 Working Days was a sufficient time period. It was noted that 20 Working Days has been in place since the DCUSA went live, i.e. it is not being added by DCP 204. The Working Group agreed to extend the time period to 60 Working Days to give Suppliers an increased safeguard that would prevent them from receiving a large number of notices over a very short time period. Clause 3.2 of the legal text was updated accordingly. It was noted that in exception circumstances, the DNO still has the ability to issue notices within the 60 Working Day period.

17.8 A suggestion was made by a Supplier respondent to clarify the drafting in Section 7 'Security Restriction Notices' to ensure that the obligations relating to Load Managed Areas detailed in Section 5 are still applicable. Due to this being the intent of the original drafting, the Working Group agreed to update the legal text.

17.9 A Distribution Business respondent suggested that any superfluous parts of Clause 5.4 'Load Managed Areas' and Clause 7.6 'Security Restriction Notices' should be deleted in order to provide greater clarity. The Working Group reviewed both Clauses, concluding that the additional information was useful and should not be removed.

17.10 A Distribution Business respondents also suggested that the contents of the Compliance Notice should be stated in order to ensure consistency.

Comment [RT8]: Update based on feedback on WPD proposed legal text ACTION

Comment [LN9]: WPD comment, what was the response to this?

Question 2 - Do you have any comments on the new obligations which will be introduced by DCP 204, as detailed in Attachment 2?

17.11 Three respondents did not have any comments on the new obligations which will be introduced by DCP 204.

17.12 A Supplier respondent raised concerns regarding the cost associated with managing customer queries and concerns, which was noted by the Working Group. The Supplier respondent also suggested that the implementation date is reviewed to ensure that it takes into account when the majority of regions would have WAN coverage.

17.13 Some Working Group members expressed a preference for the implementation date to be amended to give a greater notice period as the DCP 204 obligations cannot come into place until SMETS2 is available and DCC has gone live. As a result, the Working Group considered a 1 September 2016 implementation.

17.14 Two Supplier respondents raised concerns regarding the 600 second Randomised Offset Limit, which had been reiterated by Ofgem. The rationale was later clarified by National Grid, who confirmed that:

"The argument for setting the randomisation period at 600s comes down to a consideration of how smart metering will change the profile and volatility of demand leading to additional costs for consumers due to the increased costs that will be incurred by the system operator in responding to this. Maximum randomisation over a half hour period will effectively mean that there is very little change from the current situation with entirely random switching. Randomisation over 600s, which I believe was proposed by the ENA, is supported by National Grid as a reasonable compromise in that it allows the utilisation of secondary response rather than, if in shorter timescales, continually depleting primary response and leaving the system operator having to secure more reserves or services as a contingency against further events on the system. Note that on the transmission system, primary response is characterised as the ability of generators or demand units to respond from 10-30 seconds after an event while secondary response covers the time period up to half an hour."

~~17.2~~17.15 Finally a Supplier respondent queried whether Load Managed Areas could be flagged within the Centralised Registration System as part of the enduring process. The Working Group agreed that this was a sensible suggestion, noting that once the

Centralised Registration System has been developed, the introduction of a Load Managed Areas flag could be reviewed.

Question 3 - Do you have any comments on the Ofgem send back letter (Attachment 3)?

17.16 One respondent did not have any comments on the Ofgem send back letter, whilst two respondents agreed with the concerns raised by Ofgem.

17.17 A Supplier respondent provided a summary of the concerns raised by Ofgem, querying whether the Working Group had sufficiently addressed each concern. The Working Group reviewed the concerns raised by Ofgem, noting that the DCP 204 Working Group chair had requested cost benefit data from Distribution Businesses with Load Managed Areas. The Working Group confirmed that a justification had been put forward with regard to why the current regime should be continued with following smart meter rollout. In relation to the minimum limit being 600 seconds, National Grid has provided the rationale behind this figure. Finally, the Working Group agreed that the risk of customer confusion needs to be mitigated, which could be done by communicating to the customer at point of installation and on an ongoing basis post installation if required. By speaking to customer at the point of installation, the Working Group noted that this would address a concern raised by a Supplier respondent regarding the confusion that randomised switching would cause.

~~17.3~~17.18 Finally, a Supplier respondent suggested that an alternative approach needs to be developed for instances whereby the Supplier cannot replicate the switching times of the old meter and the DNO does not agree the proposed switching regime. The Working Group discussed this, noting that the replication of switching times is a requirement that applies today through the replication of SSC.

Question 4 - Do you have any information that could aid the Working Group in documenting and valuing the costs and benefits of the proposal (Attachment 4 sets out the costs and benefits identified thus far)?

17.19 Four respondents did not have any further information that could aid the Working Group in documenting and valuing the cost and benefits of the proposal.

17.20 A Supplier respondent challenged the current valuing of the costs and benefits of the proposal, suggesting that significant costs would be associated with the additional communications with customers rather than minimal costs. The Working Group noted this comment, agreeing that it had been discussed previously as part of the consultation.

17.21 Another Supplier respondent commented on the wide ranging figures included within the cost benefit analysis, suggesting that this indicates a lack of accuracy. The Working Group highlighted that the wide ranging figures were due to the methodology of the report and where issues may arise due to the nature of the network and geography. Further to this the below information was provided in response to this consultation:

"Regarding the values detailed in the attachment 4 the £161million to £718million range is due to the way the work was scoped in order to ensure that the work captured the aspects and locations of our SHEPD network that would likely be most impacted by the withdrawal of the RTS system. The aspects of our distribution system studied were:

- *Generation (principally embedded generation across the island groups);*
- *33kV distribution network;*
- *33/11kV primary substations;*
- *11kV distribution network;*
- *11kV/LV transformers; and*
- *Security of supply.*

There are also specific issues related to the geography of the SHEPD licence area so the study considered the impact at six geographic locations, these were:

- *Islay;*
- *Skye;*
- *The Orkney Islands;*
- *The Shetland Islands;*
- *The Western Isles; and*
- *Dundee (as an example of a typical urban area).*

To allow for the completion of the study in the requisite timescale and manage the extent of the associated workload, a process was developed that involved the detailed study of one or two regions. Details of the use of the RTS in different scenarios would provide information that would allow extrapolations to be performed for the other regions. The highest detail was given to Shetland, a medium level to Orkney and lower levels to the remaining locations.

The £161 million figure is therefore accurate as an estimate for the minimum level of reinforcement that would be required to manage network issues associated with an increase in the coincidence of load.

It should also be noted that this figure is based on DPCR5 allowed expenditure, i.e. Ofgem, Electricity Distribution Price Control Review Final Proposals – Allowed revenue – Cost assessment appendix, December 2009. It should therefore be recognised that that any future reinforcement work would incur a higher cost.

Question 5 - Do you have any further comments?

17.22 Two respondents did not have any further comments on the second DCP 204 consultation.

17.23 Prior to the discussions had regarding the consultation responses and the resultant amendments to the legal text, a Supplier respondent had noted that they were not supportive of the change. However the respondent confirmed that the amendments made had addressed some of their concerns.

17.24 A Supplier respondent suggested that the issues DCP 204 seeks to address are not a retail responsibility. The Working Group discussed this, noting that the requirements on Suppliers under DCP 204 is to work with DNOs to address network issues based on the knowledge that the DNO has. The Working Group also noted that the change would provide Suppliers with a greater level of information than at present.

17.25 A Distribution Business respondent noted that the intent of the change was to simplify the Security Restriction Notice process, which they did not believe had been addressed. The Working Group noted this comment, agreeing that the simplification of the Security Restriction Notice had been addressed.

~~17.4~~

~~17.5~~

18 ASSESSMENT AGAINST THE DCUSA OBJECTIVES

19.1 The Working Group considers that the following DCUSA Objectives are better facilitated by DCP 204~~xxx~~.

General Objective One - The development, maintenance and operation by the DNO Parties and IDNO Parties of efficient, co-ordinated, and economical Distribution Network

19.2 General Objective One is better facilitated by DCP 204 as the purpose of this CP is to make sure that DCUSA Schedule 8 is suitable for smart metering. It is not mandating any registration system changes or new data flows. Relative to the current baseline DCP 204 better facilitates Objective 1 by helping market participants discharge their current obligations more clearly as we move towards smart metering. The CP is a clarification of existing obligations and making sure that they are fit for purpose to meet the requirements of changing technologies. In particular ensuring that where Smart Meters are being rolled out, specifically in LMAs, Distributors will maintain the ability to influence the timing of load switching.

19.3 The timing of load switching is an essential tool for Distributors as a means of maintaining Security of Supply in certain circumstances. The potential for these capabilities to be used to avoid or defer network reinforcement can provide Distributors with an economic and efficient alternative to network investment in some situations.

General Objective Five - Compliance with the Regulation on Cross-Border Exchange in Electricity and any relevant legally binding decisions of the European Commission and/or the Agency for the Co-operation of Energy Regulators.

19.4 The CP supports compliance with Clause 11 in Article 3 (Public service obligations and customer protection) of Directive 2009/72/EC of The European Parliament and of the Council dated 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC.

19.5 The Working Group believes that the CP is neutral against the remaining DCUSA Objectives.

20 DCP 204 - LEGAL DRAFTING

21.1 The proposed legal drafting of DCP 204 has been considered by the Working Group, and reviewed by Wragge & Co, and is provided as Attachment 1.

21.2 In order to achieve the intent of the CP, the main elements of the draft legal text proposes that:

- Existing RTS and timeswitch switching times (and other switching characteristics) are replicated in a smart meter on installation, unless otherwise agreed between the Supplier and Distributor, within LMAs.
- Smart meter installations are deployed in such a manner, through use of Randomised Offset capabilities and management of load switching times, that coincidence of load switching is minimised. The proposed legal drafting requires that a Randomised Offset Limit is applied to all smart meters where appropriate functionality is available. The proposed legal text mandates the setting of a Randomised Offset Limit for all capable meters, and not just those that have directly switched load, as a smart meter can enable customers to automatically

switch their own load in response to changes in price (for example on multi-rate tariffs). To mitigate the risk of coincidence of demand there is a need to randomise the switching times for tariffs as well as controlled load and the obligation of setting the Randomised Offset Limit for smart meters achieves this.

- Smart Meter switching times are particularly managed in LMAs, including changes to existing Load Switching Regimes and new installations.

21.3 The proposals are based on the existing structure of Schedule 8 but seek to specifically refer to the key features and characteristics of Load Switching Devices which are of importance to Distributors.

21.4 The text also aims to simplify the process of ‘Security Restriction’ notifications to Suppliers, by combining the current ‘Provisional’ and ‘Firm’ Security Restriction process into one.

22 ENVIRONMENTAL IMPACT

22.1 In accordance with DCUSA clause 11.14.6, the Working Group assessed whether there would be a material impact on greenhouse gas emissions if DCP 204 were implemented. The Working Group did not identify any material impact on greenhouse gas emissions from the implementation of this Change Proposal.

23 ENGAGEMENT WITH THE AUTHORITY

23.1 Ofgem has been fully engaged throughout the development of DCP 204 as a member of the Working Group.

24 IMPLEMENTATION

24.1 The proposed implementation date for DCP 204 is 1 September 2016, which will enable Distributors to review all existing LMAs and develop a means to provide the granular MPAN data that is required. It is also noted that the amendments to Schedule 8 under DCP 204 are intended for the smart metering mass rollout phase which has not yet commenced.

24.2 DCP 204 is classified as a Part 1 Matter and therefore will go to the Authority for determination after the voting process has completed.

25 PANEL RECOMMENDATION

25.1 The Panel initially approved the first DCP 204~~this~~ Change Report at its meeting on **15 April 2015**. The Panel considered that the Working Group had carried out the level of analysis required to enable Parties to understand the impact of the proposed amendment and to vote on DCP 137.

25.2 Following the receipt of Ofgem's Send Back Letter on 19 June 2015, the Working Group reconvened. The Panel approved the updated Change Report at its meeting on DATE MONTH YEAR.

~~25.2~~25.3 The timetable for the progression of the CP is as follows:

Activity	Date
Change Report issued for voting	20 November 2015
Voting closes	11 December 2015
Change Declaration	15 December 2015
Authority Determination	21 January 2016[9]
DCP 204 Implemented	1 September 2016~~5~~

26 NEXT STEPS

[9] This date may be affected by the Ofgem Christmas publishing moratorium

Comment [RT10]: December Panel meeting.

Send legal text to DCUSA legal advisor

26.1 Parties are invited to consider the proposed amendment (Attachment 1) and submit their votes using the Voting form (Attachment 2) to dcusa@electralink.co.uk by **day/month/year**.

Comment [LN11]: Needs updating

26.2 If you have any questions about this paper or the DCUSA Change Process please contact the DCUSA by email to dcusa@electralink.co.uk or telephone 020 74322842 ~~30XX~~.

ATTACHMENTS

- Attachment 1 – DCP 204 Legal Text
- Attachment 2 – Voting Form
- Attachment 3 – Randomised Offset Value
- Attachment 4 – DCP 204 Consultation Documents
- Attachment 5 – LMA Notification Template
- Attachment 6 – Existing Load Managed Areas
- Attachment 7 – DCP 204 CP Form
- Attachment 8 – Ofgem Send Back Letter
- Attachment 9 – Second Consultation Document
- Attachment 10 – Domestic Supplier Forum Slides

Comment [RT12]: Cross check attachments against change report content ACTION