CDCM charging condition report to Ofgem
Generation charging in generation dominated areas
1 September 2010

Generation charging in generation dominated areas

Introduction

1. This paper is submitted by the Energy Networks Association on behalf of the 14 regional electricity distribution licensees (DNOs) in Great Britain in response to one of the conditions placed by Ofgem on its approval of the common distribution charging methodology (CDCM).[1]

2. The condition required DNOs to develop, where appropriate, a charging method that would apply to generators that are covered by the CDCM and are linked to generation dominated areas.

3. The conclusions presented at the end of this paper represent the collective view of the DNOs.

4. The Common Methodology Group (CMG) was formed by the DNOs to take forward work on Ofgem's October 2008 proposals for a common distribution charging methodology (the CDCM and the EDCM).[2] The CMG established workstream B (WSB) to develop the tariff model and its underlying principles for the EDCM.

5. WSB, which is open to Ofgem and other stakeholders, has developed and considered several options for charging CDCM generators in generation dominated areas. This paper represents the output of the work done by WSB on this issue.

6. This paper is structured as follows:

   a) We provide some background information.

   b) We examine the question how to identify a generation dominated area.

   c) We examine different options for charging methods.

   d) We look at the merits and drawbacks of each option.

   e) We provide a conclusion and our proposed way forward.

Background

7. On 20 November 2009, Ofgem published its decision on the conditional approval of the CDCM.

8. The approval of the CDCM was subject to conditions, one of which is "The methodology for generator tariffs in generation dominated areas". This condition is described in Annex 1 of Appendix 2 of Ofgem's November 2009 document, the text of which is reproduced below:

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[1] Ofgem (2009) Decision document on the common distribution charging methodology at lower voltages, ref 140/09

[2] Ofgem (2008) Delivering the electricity distribution structure of charges project, ref 135/08

> The methodology for generator tariffs in generation dominated areas:
>
> Our March 2009 decision document sets out that the methodology for generator charging will apply in the case of demand dominated network areas. The DNOs' CDCM submission to us does not explain what approach has been considered in respect of generation dominated areas and if and when such an approach might apply. We consider this is an omission from the submission.
>
> We require the DNOs to develop - where appropriate - a charging method for generation dominated areas and to justify their position in order to deliver on the requirements of our March 2009 decision document. This will involve a consideration of the options for charging in generation dominated areas, which are not necessarily locational. We note that the key issue to resolve whilst there is an average model is how the 'average' situation is determined and when this approach is no longer appropriate.
>
> This condition should be met by 1 September 2010.

9. Paragraphs 2.10 to 2.14 of Ofgem’s November 2010 document are also relevant to this subject, and are reproduced below:

> 2.10. In our CDCM consultation we noted that DNOs had not covered off the issue of how to charge generators where the network is generation rather than demand dominated. This was a requirement in our March 2009 decision document on the structure of charges project.
>
> 2.11. Six of seven DNO groups argue in their responses that they do not consider this area of work should be a conditional approval and that we have not been clear enough what is required to satisfy the condition.
>
> 2.12. We agree that the CDCM is an average charging model and that any move to distinguish demand and generation dominated areas presents certain issues for the CDCM, however we are keen that the DNOs think through this issue and the available options (which are not necessarily locational charging) more fully in order to deliver on the requirements of our March 2009 decision document. This will require them to develop — where appropriate — a charging method for generation dominated areas.
>
> 2.13. We note the amount of generation being forecast to connect to the DNOs’ networks and we are concerned that the DNOs have not addressed this in their submissions to us. We consider that this remains a sufficiently important area of charging to warrant a formal conditional approval.
>
> 2.14. This condition should be met by 1 September 2010.

10. Paragraphs 1.4 to 1.8 of Appendix 1 of the same document relate to the consultation exercise carried out by Ofgem prior to publishing its decision:

1.4. The DNOs argue that the requirements under this condition are not clear. In particular, they are not clear whether Ofgem expects them to implement locational charges or whether to employ a different averaging approach to the method. DNOs argue that clarity is required over the definition of 'generation dominated' networks, noting that different conclusions would potentially be obtained depending on whether the installed generation capacity in every substation is considered or whether the installed capacity is corrected by the typical load factor of the generation. They note that another approach to this issue would examine how many substations actually experience 'reverse flows' to higher voltage levels during the year.

1.5. Six DNOs (ENW excluded) believe that it would be preferable that this area is not identified as a condition for the approval of the CDCM, but suggest this issue should instead be dealt with under open governance arrangements. They indicate that they would take this issue forward in time for the implementation of EHV charging methodologies in April 2011. CN suggests that it would be more appropriate to make approval of the CDCM conditional on the DNOs raising the issue within the open governance arrangements. CE flags that DNOs may not be able to deliver an optimal solution to this issue due to restrictions of the settlement system (not disaggregating by geographic location).

1.6. ENW is concerned about the lack of clarity over the requirements of the condition and says that the short time limit for the condition is inadequate for a comprehensive review of the issue.

1.7. The REA maintain that given the non-locational nature of the model, and given that generators are credited only for the benefit they provide above their voltage of supply, an assumption that the network is demand dominated is appropriate. They argue that even if a network is generation dominated, treating generators that operate in such areas differently without also given extra credit to generators that operate in areas where they provide more than average benefit appears to be a one-sided application of cost reflective charging.

Our view

1.8. We note concerns over the practicality of determining generator charges at lower voltages on a locational basis. We require the DNOs to further justify their position using quantitative data and qualitative arguments around the options for charging, which are not necessarily locational. We note that the key issue to resolve whilst there is an average model is how the 'average' situation is determined and when this approach is no longer appropriate. We consider that the timeframe provided for work to develop a generator charging methodology, where appropriate, is adequate.

11. The following table provides the number of generators in the CDCM, by tariff type and DNO area, according to the published final charges models for 2010/2011.[3]

[3] Available from the ENA website (http://www.energynetworks.org/)

Table 1 CDCM generators, tariff type and DNO area

	Number of generators on LV tariffs					Number of generators on HV tariffs			
DNO area	**LV NHH**	**LV inter-mittent**	**LV Non-inter-mittent**	**LV Sub inter-mittent**	**LV Sub Non-inter-mittent**	**HV inter-mittent**	**HV Non-inter-mittent**	**HV Sub inter-mittent**	**HV Sub Non-inter-mittent**
CE NEDL	22	7	9			3	20		
CE YEDL	89	14		1		70			6
CN East	28		9			1	102		
CN West	16		10			2	68		
EDF EPN	448	4	7	6	7	28	41		
EDF LPN	279	1	4			12	8		
EDF SPN	346	1	5			1	41		
ENW	2	1	6		3	17	105	5	
SPEN SPD	10	4	4			27	27		
SPEN SPM	5	3	3	5	5	17	17	10	10
SSE SEPD		19					99		
SSE SHEPD		6	34			48	116		
WPD Wales						3	20		
WPD West						11	48		

What is a generation dominated area?

12. In the absence of a commonly accepted definition of a generation dominated area, the DNOs have developed a definition that generation dominated areas are those served by substations or substation groups (substations are grouped together where they operate in parallel under normal operating arrangements) where thermal reinforcement of substation assets is more likely to be caused by generation than demand. Generators served by such substations or substation groups are deemed to be in a generation dominated area.

13. We propose a two-test process to identify substations or substation groups that are potentially generation dominated.

14. Test 1 involves identifying substations or substation groups that are “generation heavy”, i.e. whether the power flow in the “reverse” direction is likely to dominate power flow in the “normal” direction.

15. Test 2 is to identify those generation heavy substations or substation groups that are likely to face generation-led thermal reinforcement over a 10-year horizon.

16. We do not include HV/LV substations in our analysis due to the very large numbers involved and difficulties in obtaining data on power flows through these substations.

17. We describe the mechanics of tests 1 and 2 below. All references to substations may include substation groups where individual substations operate in parallel under normal operating arrangements.

Test 1

18. DNOs would identify each EHV substation (whether primary, BSP or GSP) used in its network that meets the following test:

    MAX(0, MAXD – GC*F) < MAX(0, GC – MIND)

    Where:

    MAXD is the gross maximum demand served by the substation, including latent demand. This information is likely to be included in the LTDS.

    MIND is the estimated gross minimum demand served by the substation. This is derived by applying the ratio used as part of the EDCM WSA power flow modelling to MAXD.

    GC is the estimated gross installed or authorised generation capacity in the network served by the substation.

    F is a factor capturing the probability of generation. Figures to be taken from tables 2.1A, 2.1B, 2.2A and 2.2B within P2/6, averaged where necessary (using generation capacity as weights).

19. The number on the left hand side of that inequality (MAX(0, MAXD – GC*F)) is a measure of surplus demand in the maximum demand scenario. The number on the right hand side of the inequality (MAX(0, GC – MIND)) is a measure of surplus generation in the minimum demand, maximum generation scenario.

20. If the surplus generation in the minimum demand, maximum generation scenario is greater than the surplus demand in the maximum demand scenario, the substation is deemed to be generation-heavy.

Test 2

21. For each substation that is deemed to be generation-heavy following the first step, a further test is applied as follows:

$FC*0.8 < GC*(1.01)^{10} - MIND*(1.01)^{10}$

Where:

FC is the firm capacity served by the substation

MIND is the estimated gross minimum demand served by the substation. This is derived by applying the ratio used as part of the WSA power flow modelling to MAXD.

GC is the estimated gross installed or authorised generation capacity in the network served by the substation.

F is a factor capturing the probability of generation. Figures to be taken from tables 2.1A, 2.1B, 2.2A and 2.2B within P2/6, averaged where necessary (using generation capacity as weights).

0.8 is a factor reflecting that summer firm capacity is lower than winter firm capacity

$(1.01)^{10}$ assigns a 1 per cent growth rate to generation capacity and minimum demand over a 10 year period.

22. The second test determines whether the generation-heavy substations identified are likely to require thermal reinforcement in the next 10 years using an assumed long term growth rate of 1 per cent. Substations that meet the second test are deemed to be generation dominated.

Results of the tests

23. The following table provides the number of potentially generated dominated substations in each DNO area following the application of tests 1 and 2. This table does not include customer-owned substations.

Table 2 Potentially generation dominated substations, by DNO area

DNO area	Level	Total substations	Generation heavy substations	Potentially generation dominated substations
CE NEDL	GSPs	18	2	0
	BSPs	49	5	4
	Primaries	217	5	0
CE YEDL	GSPs	23	1	0
	BSPs	80	5	0
	Primaries	392	11	4

DNO area	Level	Total substations	Generation heavy substations	Potentially generation dominated substations
CN East	GSPs	14	0	0
	BSPs	69	0	0
	Primaries	430	1	0
CN West	GSPs	15	0	0
	BSPs	28	2	2
	Primaries	237	2	1
EDF EPN	GSPs	22	0	0
	BSPs	82	2	0
	Primaries	456	6	3
EDF LPN	GSPs	14	0	0
	BSPs	15	0	0
	Primaries	107	2	1
EDF SPN	GSPs	12	0	0
	BSPs	49	0	0
	Primaries	232	1	1
ENW	GSPs	16	2	2
	BSPs	66	3	0
	Primaries	366	4	1
SPEN SPD	GSPs	81	7	6
	BSPs	N/A	N/A	N/A
	Primaries	392	3	1
SPEN SPM	GSPs	17	4	0
	BSPs	34	1	1
	Primaries	324	2	2

DNO area	Level	Total substations	Generation heavy substations	Potentially generation dominated substations
SSE SEPD	GSPs	20	0	0
	BSPs	108	2	0
	Primaries	482	4	4
SSE SHEPD	GSPs	66	17	14
	BSPs	N/A	N/A	N/A
	Primaries	427	11	10
WPD Wales	GSPs	10	0	0
	BSPs	75	0	0
	Primaries	217	2	0
WPD West	GSPs	11	0	0
	BSPs	47	0	0
	Primaries	327	2	0
Total	GSPs	339	33	22
	BSPs	702	20	7
	Primaries	4,606	56	28
	TOTAL	**5,647**	**109**	**57**

24. The data in the table above indicate that:

a) The number of generation heavy substations across all DNO areas is 109 out of a total of 5,647, approximately 2 per cent.

b) The number of potentially generation dominated substations across all DNO areas is 57 out of a total of 5,647, approximately 1 per cent.

c) Across all DNO areas, approximately 6.5 per cent of GSPs, 1 per cent of BSPs and 0.6 per cent of primary substations are potentially generation dominated.

d) Of the 22 potentially generation dominated GSPs, 20 are in Scotland (SSE SHEPD and SPEN SPD areas).

Options for charging in generation dominated areas

25. This section discusses the various options that DNOs have considered as part of their efforts in meeting Ofgem's condition.

Option A — No change

26. Under this option, no change would be made to existing CDCM generation tariffs.

27. The analysis in the previous section reveals that there are a relatively small number of potentially generation dominated substations in most DNO areas.

28. A possible exception is GSPs in Scotland. Twenty of the 22 generation dominated GSPs are in Scotland. These GSPs usually serve EHV generators, which are not covered by the CDCM.

29. This would support the view that the distribution network is generally demand dominated. Our analysis has not provided us with any evidence that the current averaged charging method for generation is not currently appropriate.

Option B1 — Create additional tariffs for all HV/LV generation

30. Option B1 involves the creation of additional CDCM tariffs that apply to generators that are served by generation dominated areas.

31. The definition of generation-dominated areas uses substation data. For circuits, whether they are generation-dominated must be inferred from the classification of the relevant substation. The relevant substation is the one that is supplied by the circuit: for example, if a 33kV/11kV substation is generation dominated, then the 33kV circuit that supplies it is also likely to be generation dominated.

32. Generators would not be paid credits in respect of generation dominated network levels.

33. This option would involve the creation of the following four tariff categories:

Tariff category	Application rule	Charging rules
Area 1 generation tariffs	These apply in cases where every EHV substation above the relevant generator is generation dominated.	No generation credits would be paid in these areas. The fixed charge element of generation tariffs would still apply.
Area 2 generation tariffs	These apply in cases where the criterion for area 1 tariffs does not apply, but the EHV/HV primary substation above the relevant generator is generation dominated.	Generation credits would be restricted to the transmission exit, 132kV/EHV, and 132kV network levels. The fixed charge element of generation tariffs would still apply.

Tariff category	Application rule	Charging rules
Area 3 generation tariffs	These apply in cases where the top-level substation is generation dominated, but the primary substation above the relevant generator is not generation dominated.	Generation credits in these areas would be restricted to primary substations and below only. The fixed charge element of generation tariffs would still apply.
Other (demand dominated generation tariffs)	All other generators.	The current CDCM rules would apply.

34. For each of the existing generation tariffs, this would create four variants, depending on which category the generator falls under. This would take the number of generation tariffs from 21 to 84.

35. The following reasons were relied upon to restrict the types of generation tariffs to the above short list:

    a) Given that there are seven network levels in the CDCM, creating tariffs that would take into account each of the different combinations of generation dominated network levels would result in multiplying the existing number of tariffs by up to 128 (over 2,000 tariffs)

    b) Data on HV/LV substations are not necessarily available, and the complexities for suppliers of having to deal with different LV generation tariffs on a highly disaggregated basis might well outweigh any supposed cost-reflectivity benefits.

36. Under a generation-dominated 132kV/EHV substation (BSP), a generation-dominated 132kV/HV substation, and in Scotland under a generation-dominated EHV/HV substation, generation credits, if paid under the same method as envisaged above, would be restricted to a transmission exit element — a small element which does not relate to the avoidance of investment in the distribution network. It would make sense to zero out credits in area 1.

Option B2 – Only create additional tariffs for HV generation

37. Option B2 is to restrict any additional tariffs to HV generators only. There is a risk that a large number of new LV generators might connect to the network in the future, and option B2 would reduce the administrative burden in relation to those.

38. This simplifies the task of identifying existing generators that might be in generation dominated areas. It restricts the total number of generation tariffs, including new ones, to 39.

Option B3 – Only create additional tariffs for half-hourly generation

39. Option B3 is to restrict any additional tariffs to half hourly settled HV and LV generators only. There is a risk that a large number of new LV NHH generators might connect to the network in the future, and option B3 would reduce the administrative burden in relation to those.

40. This simplifies the task of identifying existing generators that might be in generation dominated areas. It restricts the total number of generation tariffs, including new ones, to 69.

Option C — Move some generators from single-rate to multi-rate tariffs

41. Option C is to designate areas as “potentially generation dominated”, in a manner administratively similar to the current load managed areas.

42. The method set out in option B1 could be used to determine which substations are generation dominated. Areas that are served by substations that are generation dominated would be designated as “potentially generation dominated”.

43. In these areas, all CDCM half hourly settled generators would be placed on three-rate tariffs, and two-rate generation tariffs would be created for CDCM non-half hourly metered generators.

44. The three-rate tariffs would have the effect that the credits per unit generated paid to generators would be lower in the amber time band than in the red time band, and lowest during the green time band.

45. Option C would involve increasing the current number of tariffs to 27. It would add complexity to the statements of use of system charges, and billing system costs for DNOs, IDNOs and suppliers.

Option D — Move all half hourly metered generators to three-rate tariffs

46. Option D is a simpler variant to option C. Option D involves moving all CDCM half hourly metered HV and LV generators to three-rate tariffs. Three-rate tariffs already exist within the CDCM.

47. The three-rate tariffs would have the effect that the credits per unit generated paid to generators would be lower in the amber time band than in the red time band, and lowest during the green time band.

48. Three-rate tariffs would not apply to HV and LV non-half hourly metered generators. They would remain on the existing single rate tariffs.

49. This option is simpler to implement, but it would not change the total credits received by intermittent generation, and would not generally change behaviour.

Option E — Apply DNO-wide probabilities of generation domination to generation tariffs

50. Option E is to calculate DNO-wide probabilities that each network level might be designated as generation dominated. These DNO-wide probabilities could be inferred from the results of the tests proposed earlier in this paper.

51. These probabilities would be used to scale down contributions to generation credits across the whole network. Option E would reduce generation credits without directly changing demand charges.

52. In addition to being non-locational, option E has the undesirable effect of potentially reducing credits to generators in demand dominated areas of the network, and is therefore not cost-reflective.

Option F — Apply DNO-wide probabilities of generation domination to all unit rates

53. Option F is to calculate the probabilities as in option E and then apply these to all generation and demand unit rates in the CDCM.

Comparison of options

54. The following table provides an overview of the merits and drawbacks of each of the options discussed earlier.

Table 3 Comparison of options

	Merits	Drawbacks
Option A	Simple and easy to implement.	Charges would remain non-locational and credits would be paid at the same rate for all generators, irrespective of whether they are in a generation dominated area or not.
Option B1	Introduces new locational tariffs. Most comprehensive of the options considered.	Introduces significant complexity in tariff structures and billing arrangements.
Option B2	Introduces new locational tariffs, and is less complex than option B1.	Introduces some complexity in tariff structures and billing arrangements.
Option B3		
Option C	Moves generators in generation dominated areas to multi-rate tariffs that would reduce credits paid during times of low demand.	Increases the number of existing tariffs for non-half hourly metered generators. For intermittent generators in generation dominated areas, assuming time of export is not correlated with time bands, it does not change the amount of credits paid compared to current method.
Option D	Moves half-hourly metered generators to multi-rate tariffs that would reduce credits paid during times of low demand. No new tariffs need to be created.	Charges would be non-locational and credits would be paid at the same rate for all generators, irrespective of whether they are in a generation dominated area or not. For intermittent generators, assuming time of export is not correlated with time bands, it does not change the amount of credits paid compared to current method.
Option E	Simple and easy to implement.	Charges would be non-locational and credits would be paid at the same rate for all generators, irrespective of whether they are in a generation dominated area or not. Both options are therefore not cost-reflective. Generation credits are reduced across the network, despite the fact that most generators are actually in demand dominated areas.
Option F		

Conclusion

55. Having considered the various options set out in this paper, and in light of their merits and drawbacks summarised in the previous section, DNOs have reached the view that option A (no change to the CDCM) is the most appropriate option for now.

56. We recognise that option A may not sufficiently address concerns about the non-locational nature of the current charging methodology. However, given the relatively small number of generators that might potentially be affected, and the extent of tariff and billing complexities raised by other options, we believe that the current "average" method is still appropriate for now.

57. However, the DNOs propose to undertake a study on the issue of tariffs for CDCM generators in generation dominated areas. The results of this study would inform the development of any future charging proposals.

58. The study would involve an investigation into:

    a) The viability and possible impact of locational charging for CDCM generation.

    b) The costs and benefits of developing a separate charging regime for these generators, including an examination of:

        i) The interaction, if any, of such proposals with developments on smart metering.

        ii) The interaction, if any, with charges for demand users.

        iii) The potential impact of locational charging for CDCM generation on the development of micro-generation.

59. The study would be carried out by external consultants working under the direction of the CMG but using the DCMF for the initial consultation process. We will consult with stakeholders on the initial findings from the study before the final conclusions from the study are published.

60. An indicative timetable for the study is provided below:

Milestone	Date
Finalise the scope and terms of reference for the study	31 October 2010
Complete the tendering process and appointment of consultants	31 December 2010
Present initial findings from the study	31 March 2011
Start of consultation process	30 April 2011
End of consultation period	Mid-June 2011
Submit final report with conclusions	31 July 2011

Glossary

Term	*Explanation*
BSP	Bulk Supply Point: in England and Wales it is the top-level substation on the distribution network.
CDCM	The Common Distribution Charging Methodology.
CMG	Common Methodology Group of the DNOs.
DCMF	Distribution Charging Methodologies Forum, whose membership includes Ofgem, DNOs, LDNOs, suppliers, generators and customers.
DCUSA	The Distribution Connection and Use of System Agreement.
EDCM	The EHV Distribution Charging Methodology: One of the distribution charging methodologies (FCP or LRIC) for higher voltage users specified in Ofgem's 31 July 2009 document.
EHV	Extra High Voltage: In this document, EHV normally refers to nominal voltages of at least 22kV.
GSP	Grid Supply Point: where the distribution network is connected to a transmission network, except an offshore transmission network.
HV	High Voltage: Nominal voltages of at least 1kV and less than 22kV.
kV	Kilovolt (1,000 Volts): a unit of voltage.
kVA	Kilo Volt Ampere: a unit of network capacity.
LDNO	Licensed Distribution Network Operator. This refers to an independent distribution network operator (IDNO) or to a distribution network operator (DNO) operating embedded distribution network outside its distribution service area.
LTDS	Long Term Development Statement published by the DNOs.
LV	Low Voltage: Nominal voltages of less than 1kV.
Unit rate	A charging or payment rate based on units distributed or units generated. Unit rates are expressed in p/kWh. Tariffs applied to multi-rate meters and/or using several time bands for charging have several unit rates.
WSA	Workstream A, set up by the CMG to steer the development of power flow modelling for the EDCM
WSB	Workstream B, set up by the CMG to develop the tariff model and its underlying principles.