MIG Generation Dominated Areas

Report from the MIG Generation Dominated Areas working group

1. The working group was set up by the Methodologies Issue Group (MIG) to explore three charging options for HV connected generators and where appropriate to submit a DCUSA change proposal.

2. An outline of the three options formed the conclusions from the DNO's Generated Dominated Area submission to Ofgem dated 13 June 2011. The workgroup have utilised this submission, which included a report by Frontier Economics dated April 2011 and Ofgem's decision in relation to completion of CDCM approval condition – generation dominated areas.

3. The working group has expanded the design and understanding of the three options and worked through the available data. The outcome is that the DNOs have developed detailed specifications for each of the options, identified potential generation dominated areas and measured the impact on HV sites charges.

Background

4. On the 1 September 2009, DNOs submitted their proposals for a Common Distribution Charging methodology. The CDCM sets out the methodology for calculating use of system charges that apply to both demand and generation customers connected to the HV and LV networks. Essentially the methodology attributes charges to demand users based on reinforcement costs and also applies credits to generators where reinforcement costs are offset by the generation.

5. On 20 November 2009, Ofgem published its decision to approve the CDCM. Their decision to approve the methodology was subject to five conditions, one of which was that DNOs should review the issue of how to charge generators where the network is or will become dominated by generators as opposed to demand customers.

6. The DNOs employed Frontier Economics to conduct this review which was undertaken during the first quarter of 2011. Their report "Evaluating the case for introducing locational DUoS charges for CDCM generators" was delivered in April 2011. The DNOs submitted a conclusion report to Ofgem on the 13 June 2011. This report set out a detailed assessment of the issue and the options available for developing the CDCM.

7. On the 13 July 2011, Ofgem decided that DNOs had fulfilled the requirements of the condition and supported the proposal to progress the development of options through the MIG.

8. The MIG set up the Generation Dominated Areas working group on 29 September and the first meeting was held on 18 October 2011.

Generation Dominated Areas Issue.

9. The CDCM provides a p/kWh credit to HV and LV connected generation customers irrespective of where they are located on the network. This credit reflects the notion

that on average, local generation can reduce the need for network reinforcement by offsetting any local growth in demand. In addition to the credit a fixed charge (p/MPAN/day) or reactive charge (p/kVArh) may also apply.

10. It is possible that there might be parts of the HV and LV distribution networks where local generation capacity is forecast to grow to the extent that it exceeds local demand at certain times of the year. In these situations it might be the case that generation triggers network reinforcement rather than preventing it.

11. It is against this background that Ofgem required DNOs to consider how to charge generators in these circumstances.

12. The Frontier Economics report gave two main conclusions:

    (a) that there is a strong case against introducing a complex locational charging regime as things stand today,

    (b) that there may be a case for considering changes to the charging regime for HV connected generators.

13. Consequently the DNOs' conclusion report to Ofgem proposed to investigate changes to the charging regime for HV generators and suggested three 'dynamic charging' options. The report also proposed that these options would be explored by setting up a MIG working group to bring forward an appropriate DCUSA modification proposal.

14. Since its first meeting the MIG Generation Dominated Areas working group has completed the following work:

    (a) Modified the approach used for identifying generation dominated areas

    (b) Developed detailed specifications for each of the three charging options

    (c) Identified the generation dominated areas

    (d) Measured the impact on charges for each of the options

Identifying Generation Dominated Areas

15. The Frontier Economics Report defined a generation-dominated area as "a primary substation where thermal reinforcement is more likely to be caused by generation than demand, within a specific time period".

16. The working group use a variation of the test for generation dominated area that was detailed in the Frontier Economics Report. The group added a second test as it was felt inappropriate to remove a benefit signal from a generator where they might still be supporting a demand loaded substation. The second test validates whether the generation loading is higher that the demand loading.

17. The tests have been constructed to use readily available data from the DNOs networks. The data source used is from the DNO's Long Term Development Statement (LTDS) and this data is published on the DNOs website. Other data has been sourced from DNOs FBPQ submissions. The tests are conducted on each substation separately unless the substations form part of a connected network group.

18. The first test considers whether generation is driving the need to reinforce the substation and the second test considers whether demand is a larger factor in the need to reinforce. The tests are conducted at certain points in the future based on a number of years from the latest available data.

19. The work group are using 2.5 years, 5 years, 7.5 years and 10 years from the latest available date to determine whether a substation will show as being generation dominated at that point in time. The results for these points in time are used later in each of the charging options.

20. Appendix 1 contains more detail of the formulae used for each test.

21. A spreadsheet template has been developed to enable each DNO to populate data from their LTDS to determine those substations which would become generation dominated in the future if the assumptions happen in reality.

Specifications for each charging option

22. Each of the charging options has been expanded into more detailed charging specifications.

23. Option 1 represents the introduction of a simple locationally varying charging regime for HV generators. Under this option every HV generator would be assigned to a set of generation charges based on the primary substation that they are electrically connected to. Each primary substation would be set to one of four probabilities of generation dominance based on the number of years to when it would be deemed generation dominated. The level of generation dominance would determine how much generation credit is removed from these sites.

24. Option 2 would introduce a simple arrangement for reducing the amount of credit paid to all HV generators in a DNO wide area. The amount of reduction would reflect the percentage of primary substations that are generation dominated. The two existing HV generation tariffs would remain but with a reduced credit.

25. Option 3 would remove credits from any HV generator that was electrically connected to a Primary substation where that substation was deemed to be generation dominated within 7.5 years. Two new HV generation tariffs would be introduced both with zero credit applied.

26. The specifications for each of the options are provided in more detail in Appendix 2.

27. The work group has identified that it is possible to have many other options or indeed variants of the options. As part of the evaluation process the work group has tried to balance the establishment of a solution which is overly complex with an approach which can be seen as sensible and transparent.

28. Variants which have been considered include:

    (a) Only reducing the level of the credit that is applied at the network level for those assets which are forecast to need reinforcement i.e. primary substation.

    (b) Keeping the credit in place for those sites which participate in Generation Side Management (GSM).

29. At this stage no variant has been completely ruled out although the desire is to develop an approach which is straightforward to implement within acceptable timescales.

Option Preference

30. The working group have discussed the options based on charging principles and the impact of the approach. Each of the options has the desired impact of reducing the amount of credit that would be paid to generators in areas that were deemed to be generation dominated. It was also felt that each option would be relatively straightforward to apply.

31. One of the major differences in the options was the level of granularity of application. This could vary the amount of step change of the credit provided or the size of the area deemed generation dominated. It was felt that it was better to provide a graduated credit reduction rather than a step change.

32. Option 1 has the advantage that the credit applied would reflect the level of generation dominance, including removing all of the credit if appropriate. Option 1 also provides a locational charge and any reduction in the credit does not affect generators in other non-generation dominated areas. However this option requires the most amount of detail to apply.

33. Option 2 has the advantage that it is the simplest and therefore possibly the easiest to understand. It is also the approach that has the most gradual change in the reduction of credits. The approach is applied over the whole DNO area and the reduction will apply to generators on an average basis. However, this will have the perverse effect of still providing credits, although reduced, to generators in generation dominated areas and reducing credits to generators in demand dominated areas.

34. Option 3 has the advantage that it provides a locational signal and will cease to pay credits to generators in generation dominated areas. However there is no granularity in that signal. As soon as a Primary substation is forecast to be generation dominated then the credit would cease to be paid for any HV generator that are electrically connected to it.

35. The workgroup feel that Option 1 would be the solution which would better meet the objectives of the charging methodology.

Impact on charges

36. Work has been undertaken to analyse the impact of the proposal on each DNO. The following table provides the results to date where DNOs have completed the exercise.

37. Column 1 “Current total HV generation 2012” provides the total payment to HV connected generators for each DNO. The data is estimated revenue for the 2012 – 2013 charging year.

38. Column 2 “Current HV GDA generation 2012” provides the total payment to HV connected generators for each DNO, where they are deemed to be connected to a Generation Dominated Area. The data is estimated revenue for the 2012 – 2013 charging year.

39. Column 3 “Option 1” provides the total that would be paid to HV connected generators for each DNO, where they are deemed to be connected to a Generation Dominated Area under GDA option 1 solution. The data is estimated revenue for the 2012 – 2013 charging year.

40. Column 4 “Option 2” provides the total that would be paid to all HV connected generators for each DNO, regardless of whether they are deemed to be connected to a Generation Dominated Area under GDA option 2 solution. The data is estimated revenue for the 2012 – 2013 charging year.

41. Column 5 “Option 3” provides the total that would be paid to HV connected generators for each DNO, where they are deemed to be connected to a Generation Dominated Area under GDA option 3 solution. The data is estimated revenue for the 2012 – 2013 charging year.

42. Table - Network area summary of options

DNO Area	Current total HV generation 2012	Current HV GDA generation 2012	Option 1	Option 2	Option 3	Number Substations	Number GDAs
ENWL	-£8,250,259	-£931,514	-£209,928	-£7,931,854	-£185,365	365	20
NPGNEDL	-£1,574,223	-£178,474	-£178,474	-£1,574,223	-£178,474	254	2
NPGYEDL	-£2,059,429	-£756,414	-£70,901	-£2,047,043	-£70,901	483	7
SEPD	-£2,740,069	-£888,025	£1,085	-£2,700,313	£1,085	592	13
SHEPD	-£5,972,606	-£1,443,462	-£74,407	-£5,725,292	-£24,137	406	38
SPD	-£2,710,997	-£1,207,935	-£532,623	-£2,658,072	-£670,948	433	29
SPM	-£1,210,965	-£406,282	-£189,200	-£1,203,640	-£257,787	619	7
UKPNEPN	-£3,500,547	-£878,854	-£371,427	-£3,429,984	-£426,491	433	23
UKPNLPN	-£772,017	-£261,512	-£90,356	-£761,233	-£12,475	108	4
UKPNSPN	-£1,207,130	-£107	£118	-£1,196,926	£118	234	2
WPDEM	-£2,900,760	-£546,300	-£304,949	-£2,653,849	-£367,131	383	52
WPDWA	-£477,602	-£407	-£26	-£473,964	£89	188	3
WPDWE	-£706,003	-£40,680	£107	-£702,068	£107	323	2
WPDWM	-£1,577,131	-£161,462	-£91,494	-£1,560,501	-£57,033	115	8

Appendix 1

1. The following tests are used for identifying a generation dominated primary substation. Where the result of both tests is TRUE then the area is defined generation dominated in the time horizon ahead of t for which the tests are being applied.

Test 1

$$FC \times SW < GC_t - MIND_t$$

Test 2

$$GC_t - MIND_t > MAXD_t - MING_t$$

If:

$GC_t = GC \times (1 + g_{DG\%})^t$
$MIND_t = MIND \times (1 + g_{MIND\%})^t$
$MAXD_t = MAXD \times (1 + g_{MAXD\%})^t$
$MING_t = MING \times (1 + g_{MING\%})^t$

Where:	Source
$\boldsymbol{FC}$ is the firm capacity served by the substation, measured in MW or MVA.	Long term development statement Table 3 – Load Data 'Firm Capacity'
$\boldsymbol{SW}$ is a factor < 1 reflecting the fact that summer firm capacity is less than winter firm capacity.	Default estimate: 0.8
GC is the lower of the total estimated installed generation capacity at the substation and the total Maximum Export Capacities of the HV generators connected to the primary.	Long term development statement Table 5 - Generation data 'Total Installed Capacity' or contracted Maximum Export Capacity
$\boldsymbol{g_{DG\%}}$ is the estimated annual percentage growth rate in distributed generation.	Frontier Economics report Table 3 DG growth rates per DNO area based on FBPQ forecasts
$\boldsymbol{MIND}$ is the estimated existing minimum demand served by the primary substation. This is calculated as the product of the observed maximum demand and a minimum demand scaling factor.	Long term development statement Table 3 – Load Data 'Maximum Demand (MW or MVA)' x 'Minimum demand Scaling Factor'
$\boldsymbol{g_{MIND\%}}$ is the annual percentage growth rate in the level of minimum demand.	Apply a minimum demand growth rate of 1%. This is consistent with the growth in demand forecasted between 2010/11 and 2014/15 in the LTDS load data tables. This growth rate is also consistent with assumptions used elsewhere, for example in the EDCM "Long Run Incremental Cost" (LRIC) methodology.
MAXD is the estimated maximum demand served by the primary substation.	Long term development statement Table 3 – Load Data 'Maximum Demand (MW or MVA)'

$g_{MAXD\%}$ is the annual percentage growth rate in the level of maximum demand.	Apply a maximum demand growth rate of 1%. This is consistent with the growth in demand forecasted between 2010/11 and 2014/15 in the LTDS load data tables. This growth rate is also consistent with assumptions used elsewhere, for example in the EDCM "Long Run Incremental Cost" (LRIC) methodology.
MING is the estimated minimum generation served by the primary substation. This is calculated as the product of the observed generation capacity and a minimum generation scaling factor.	Long term development statement Table 5 - Generation data 'Total Installed Capacity' x 'Minimum generation Scaling Factor' The scaling factor is assumed to be 0.4 until a calculated value is derived.
$g_{MING\%}$ is the estimated annual percentage growth rate in the level of minimum generation.	Frontier Economics report. Table 3 DG growth rates per DNO area based on FBPQ forecasts
t is the time horizon (n years) over which the test seeks to identify the prevalence of GDAs.	GDA meeting on 13/03/2012 agreed to test using 2.5, 5, 7.5 and 10 years.
Note: Use of MW or MVA should be consistent throughout	

Appendix 2

Specifications for charging options

Option	Definition	Charge Structure	Number of tariffs	Granularity of location	Detail required for each generator
Option 1	The introduction of a very simple locationally varying charging regime for HV generators.	Mirroring the existing HV Generation Non-Intermittent and HV Generation Intermittent charge structures.	Eight tariffs to reflect High, Medium, Low likelihood of generation dominance, the currently applied set of charges and the two current charge structures. HV Generation Intermittent – No generation dominance within 10 years – Full generation credit HV Generation Intermittent – Low generation dominance within 7.5 years – 67% of generation credit HV Generation Intermittent – Medium generation dominance within 5 years – 33% of generation credit HV Generation Intermittent – High generation dominance within 2.5 years – zero generation credit HV Generation Non-Intermittent – No generation dominance within 10 years – full generation credit HV Generation Non-Intermittent – Low generation dominance within 7.5 years – 67% of generation credit HV Generation Non-Intermittent – Medium generation dominance within 5 years – 33% of generation credit HV Generation Non-Intermittent – High generation dominance – within 2.5 years – zero generation credit The method for calculating generation dominance probability will be based on the predicted years that a substation will be deemed to become generation dominated.	Primary substation supplying HV generator. Table of all Primary Substation with probability of dominance – None, Low, Medium, High.	MPAN Primary substation Assign to None, Low, Medium, High LLFC

Option	Definition	Charge Structure	Number of tariffs	Granularity of location	Detail required for each generator
Option 2	The introduction of a simply applied regime for levying credits on HV generation where the amount of credit is reduced in each DNO area dependant on the probability of generation dominance.	Use the existing HV Generation Non-Intermittent and HV Generation Intermittent charge structures.	Two existing sets of charge structures. HV Generation Intermittent HV Generation Non-Intermittent Test for generator dominance at 5 years and then look at the firm capacity weighted number of substations that are generator dominated in this period and use this as a factor with which to reduce credits to all HV connected generators in that DNO area.	DNO area.	None.
Option 3	To amend the existing charging regime to not apply credits to HV generation in locations that are considered to be generator dominated.	Mirroring the existing HV Generation Non-Intermittent and HV Generation Intermittent charge structures.	Four sets of charges to reflect generation dominated (no credit) and the currently applied set of charges and the two current charge structures. HV Generation Intermittent – Generation dominance HV Generation Intermittent – Demand dominance HV Generation Non-Intermittent – Generation dominance HV Generation Non-Intermittent – Demand dominance	Primary substation supplying HV generator. Table of all Primary Substation with true or false GDA – None, High.	MPAN Primary substation Assign to None or High probability LLFC