Meeting report

Meeting name	Transmission Charging Methodologies Forum
Date of meeting	13th November 2013
Time	10:00am – 1:00pm
Location	National Grid House, Warwick

Attendees

Name	Initials	Company
Adam Sims	AS	National Grid (Chair)
Amy Boast	AB	National Grid (Technical Secretary)
Andrew Wainwright	AW	National Grid (Presenter)
Damian Clough	DC	National Grid (Presenter)
Stuart Boyle	SB	National Grid (Presenter)
Binoy Dharsi	BD	EDF
Frank Prashad	FP	RWE NPower
Paul Brennan	PB	Waters Wye Associates
Karl Maryon	KM	Haven Power
Garth Graham	GG	SSE
Tim Russell	TR	Russell Power
Bob Brown	BB	Cornwall Energy
Richard Mawdsley	RM	Haven Power
Jonathan Wisdom	JW	NPower
Simon Holden	SH	Adjacent Power
Alex Troth	AT	Opus Energy

Dial In

Name	Initials	Company
Kyle Martin	KM	Energy UK

All presentations and supporting papers given at the TCMF meeting can be found at:
http://www2.nationalgrid.com/uk/Industry-information/System-charges/Electricity-transmission/Methodology-forum/

1 Statement of Works / Modification application fees update – Martin Moran

1. MM presented on the proposals to change the process to connect embedded generation. The current Statement of Works process for small embedded generators has been criticised for being too long and expensive, with a lack of transparency in the process, whilst the connection process for large embedded generation has been criticised as it requires two applications and associated fees, with no single point of contact.

2. The proposal is to remove stage 1, Statement of Works, for small embedded generation. This will have the benefits of reducing timescales by around 3 months, saving the developer ~£2,000 per application and providing earlier notice of Transmission reinforcements to the TO.

3. National Grid have asked for a letter of comfort from Ofgem to remove stage 1 for small embedded generators. An attendee praised the proposal, referring to an incident where this stage had taken 11 months. Another attendee pointed out that if the urgency criteria are met in this instance, an urgent modification could be completed in a day to get the change through as a code modification.

4. For large embedded generator it is proposed to allow the generator to make one application via National Grid – either a BELLA or a BEGA. The benefits of this proposal include having a single point of contact (NGET), submitting one application / application fee, not paying a Modification Application to the DNO and potentially up front savings of ~£30k per application.

2 Ongoing Code Modifications Update – Amy Boast

5. Ongoing CUSC modification proposals were presented with updates from each. These were;
   a. **CMP213:** Project TransmiT TNUoS Developments
      i. Ofgem's impact assessment consultation has now closed
      ii. Minded to position: Diversity 1, 100% HVDC / Islands
         - To be implemented 2014/15
      iii. Indicative tariffs for 2014/15 using WACM2 methodology published this month
         - Contains specific annual load factors
   b. **CMP219:** Clarifications to User Commitment Methodology
      i. Received three responses supporting the implementation
      ii. To be presented at November CUSC Panel
   c. **CMP222:** User Commitment for non-generation users
      i. Workgroup meetings have begun
   d. **CMP 223:** Arrangements for Relevant Distributed Generators Under the Enduring Generation User Commitment
      i. Workgroup meetings have commenced
   e. **CMP201:** Removal of BSUoS charges from Generation
      i. Ofgem published minded to position to reject the proposal
      ii. Stated that proposal meets CUSC objectives but does not meet Ofgem's statutory requirements
   f. **CMP 224:** Cap on the total TNUoS target revenue to be recovered from generation users
      i. One workgroup meeting held so far
      ii. Main discussion surrounded the inclusion/exclusion of local charges on the proposed cap

3 Indicative TNUoS Charges for 2014/15 - Damian Clough

6. DC presented on the changes to the charging model since the last quarterly update:
    a. 8GW reduction in generation background
    b. 4.5GW reduction in peak demand
    c. £70m increase in allowed revenue
    d. Circuit changes e.g. Beauly Denny and London cabling

Generation Background

7. Modelled generation for 2013/14 was 82GW; the initial view for 2014/15 was 88GW and the updated view for 2014/15 is 79.7GW (8GW of generation background changes have been made throughout the year). 82GW in total was contracted for 2013/14. There is a total reduction of ~2.3GW in the contracted generation for 2014/15 compared to 2013/14; notably Peterhead's TEC has reduced by 780GW and Grain's TEC has reduced by 1,121MW. The result of these changes in generation background is a reduction in north-south flows, which in turn means that generation tariffs are reduced in the North, and increased in the South (as there is less generation in the North compared with 2013/14).
8. The indicative tariffs published in the quarterly update have a cut off date for contracted generation of 1st October 2013; any changes in contracted generation since this date have not been included in this forecast but may well affect the final tariffs (which uses contracted information as on 31st October 2013). Any reduction in contracted generation in the South may push up generation tariffs in the North and vice versa.
9. Attendees were informed they could get a copy of the models should they find them useful; contact Damian.Clough@nationalgrid.com

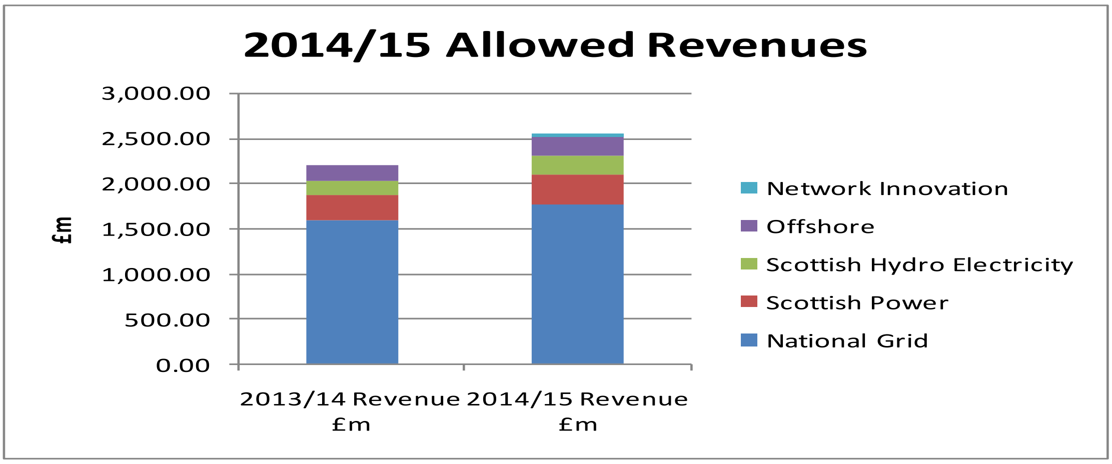
Demand Background

10. Peak demand for 2013/14 was 60,218 GW. The updated figure for 2014/15 peak demand is 56,574 GW (the previous figure was 61,299GW for 2014/15). This drop seems closer to what is currently being observed so National Grid are not challenging it. DC commented this is also down to improved forecasting of peak demand by DNO's.
11. Peak demand has reduced across the country, but is slightly less pronounced in the North & Scotland, resulting in demand tariffs increasing in the North and decreasing in the South; except for in zones 1 and 6, where peak demand is perceived to have dropped due to an increasing embedded generation in the area (North of Scotland and West Coast).

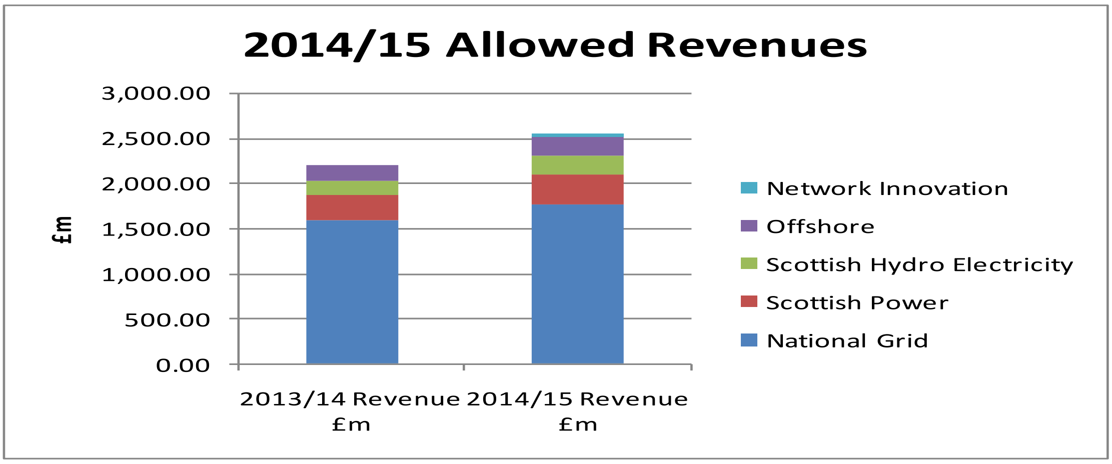
Total Allowed Revenue

12. Total Transmission Allowed Revenue is based on:
    a. information provided by SHETL, SPTL, and existing OFTOs
    b. a forecast of new OFTO revenues (informed by Ofgem & Developers)
    c. RIIO proposals

13. Total Allowed Revenue £2,542m is an increase of £345m from 2013/14. This reflects the second year of the RIIO-T1 price control and the move to a low carbon economy. The percentage of different TO's revenue requirements compared to allowed



revenue remains roughly the same. One attendee expressed concern that allowed revenue figures have appeared to increase for the Scottish TO's by 30-40% from one quarter to another, and questioned whether this was an incorrect figure they have passed on to National Grid, or if it was the actual allowed revenue that had been agreed with Ofgem. SB felt it was related to TIRG allowances but would investigate further.



Transmission Network Changes

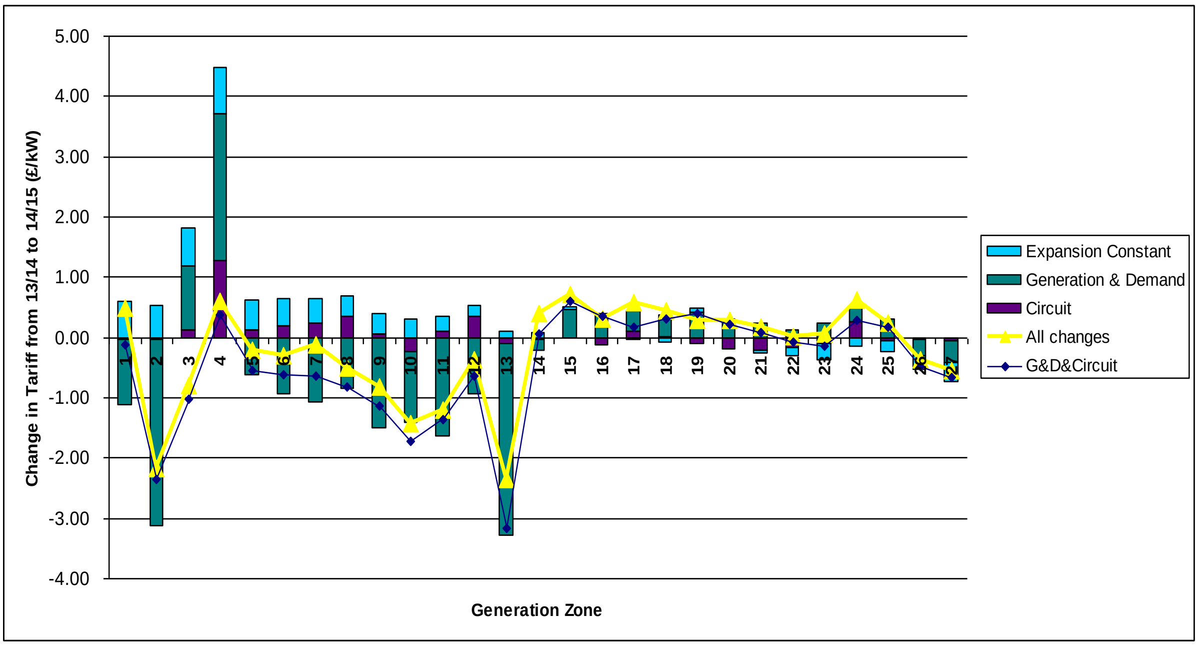
14. Key changes to this data are:

   a. **Beauly Denny:** replacing 132kV and 275kV overhead lines with 400kV overhead lines to aid power flows in parts of Scotland and increase efficiency. These works are to be completed in 2015/16 so future tariff changes are expected to reflect this. The benefit of this work is partially offset by some cabling work and TEC reductions which alters flows.

   b. **Cabling work in London**: coupled with Generation changes, this alters flows in Zones 23 and 24.

   Limited changes are expected now to this data.

15. DC presented a graph demonstrating the impact on generation tariffs due to locational changes:



16. DC presented graphs to show the change in both generation and demand tariffs in both generation and demand zones, with explanation as to the drivers of these tariff changes. Generally, generation tariffs decrease in Scotland and increase in the South, whilst demand tariffs increase above the average in Scotland and decrease in the South, due to the shift in balance between generation and demand reducing North-South flows on the network.

17. DC explained which data inputs into the tariffs are likely to change between the November Quarterly Update with indicative tariffs and final tariffs. Limited change is expected to circuit data, peak demand data, and allowed revenues, with some changes to the generation background possible based on changes declared between 1st – 31st October 2013.

18. DC explained that November's Quarterly Update included indicative tariffs for 2014/15 under the WACM2 methodology – Ofgem's minded to position for CMP213 – using the same input data as the Status Quo tariffs. This was the first time WACM2 tariffs have been produced so no comparisons to previous years have been made. Additional inputs to WACM2 compared with Status Quo tariffs are scaling factors which produce a different generation background, and Annual Load Factors (ALFs) specific to each generator (which are still subject to change).

19. DC explained that under the WACM2 methodology, the tariff is made up of different elements, namely Peak Security, Shared Year Round, Not Shared Year Round and Residual. Only conventional plant pays Peak Security; the Shared Year Round element is that which is multiplied by the ALF's. Not Shared Year Round and Residual elements are fixed for each generation zone and paid by all users.

20. DC explained that:

    a. draft tariffs for 2014/15 will be published before Christmas 2013

    b. Final Tariffs for 2014/15 will be published 31st January 2014, with efforts being made to publish 2015/16 tariff forecast on 31st January 2014.

    c. Forecasts for 2016/17, 2017/18 and 2018/19 tariffs will be published by 31st March 2014.

21. An attendee questioned when Ofgem's decision on CMP213 would be ready given the proposed implementation date of April 2014. National Grid informed the

attendees that the more time there is between Ofgem's determination and the Draft Tariff publication in December; the more dialogue there will be to accompany the Draft Tariffs. Attendees stated that, in the event that a determination was not made by Christmas 2013, they would like draft tariffs for WACM2 and Status Quo. National Grid agreed to look into publishing 2015/16 tariffs before January 2014 to provide further guidance to industry, but noted that the focus needed to be on 2014/15 tariffs at this time.

22. DC asked for feedback regarding this year's introduction of Quarterly Updates. Attendees agreed they had found the Quarterly Updates useful, however on attendee pointed out that short-term changes to significant inputs can de-value the output (e.g. allowed revenue). Attendees agreed it was a challenge to read November's update as it referenced the initial quarterly update, not the previous quarterly update, and that it would make easier reading if each new update referred to the previous update.

4 Indicative Annual Load Factors Under CMP213 WACM2 – Stuart Boyle

23. Ofgem are minded to implement WACM2 with effect from April 2014. This results in a change to the charging methodology, in that tariffs will be worked out based upon four elements: Peak Security (paid only by conventional plant), Shared Year Round, Not Shared Year Round and Residual. The Shared Year Round element is that which is impacted by ALF's.

24. SB explained how specific ALF's are calculated:

    a. The previous 5 charging years are used to set specific ALF's. For each of the previous 5 charging years an ALF is calculated:

    Max (Metered, FPN,0) summed over 17,520 HH ÷ **Sum Tec/2 over 17,520HH** = **Year X ALF**

    Of these five calculated ALF's for the five previous charging years, the maximum and minimum are removed, and the average of the remaining three ALF's taken to give the specific ALF for that unit. It was noted that the number of setttlement periods would change for a leap year.

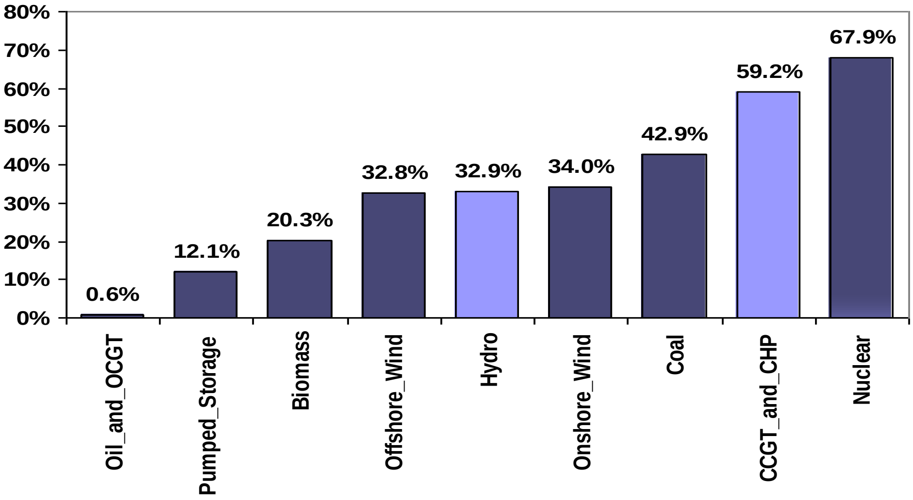
    b. If the unit only has 4 charging years of data, the ALF for each year is calculated as above and the lowest of the four is then removed, and the average of the remaining three used to give the specific ALF for the unit.

    c. If the unit only has 3 years of charging data, then the ALF's for each year is calculated as above and the average of these three figures taken to give the specific ALF for the unit.

    d. When less than three years of data is available, the average of three years is still required to give the specific ALF for the unit, so this is found using any whole years there is data available for, the generic ALF is used for any whole years which are missing, and a weighted average of actual data and generic ALF's for years which have partial data.

25. SB explained that the generic ALF is derived from the average annual output of the ten most recently commissioned GB generation of a particular generation plant type that have at least five charging years' data. Where less than ten GB generators of a particular generation plant type exist, then data from all existing generators of that particular generation plant type will be used.

26. 2014/15 Indicative Generic ALFs were shown to the attendees as below. SB explained that the ALF for offshore wind is less than the ALF for onshore wind due to the proportion of commissioning years in the data at the moment.



27. An attendee asked how dual-fuel station ALFs are calculated (e.g. coal and biomass). SB explained in this scenario the primary fuel type for this station is taken as that station's technology type. SB clarified that CHP is all CHP, not just gas.

28. SB ran through the timeline for Tariff and ALF updates and requested that National Grid are notified of errors a timely manner.

29. It was noted that, as a full year's data was not available for charging year 2013/14, National Grid had used 2008/9 to obtain five years worth of data. Attendees agreed with this approach.

5 Review of embedded charging arrangements: update – Andy Wainwright

30. AW gave an update on the focus group discussions regarding the review of embedded charging arrangements (an informal focus group was established earlier in the year to inform any potential CUSC modification proposal).

31. The focus group is primarily focussing on embedded benefits associated with TNUoS, despite there also being embedded benefits associated with BSUoS and transmission losses. The focus group agreed two remits were areas for consideration when discussing potential defects:

    a. Cost reflectivity of transmission charges on distribution connected generation

    b. Impact of transmission charges on competition between transmission and distribution connected generation.

32. AW explained that the focus group discussed three ways in which embedded generation could be argued uses the transmission system:

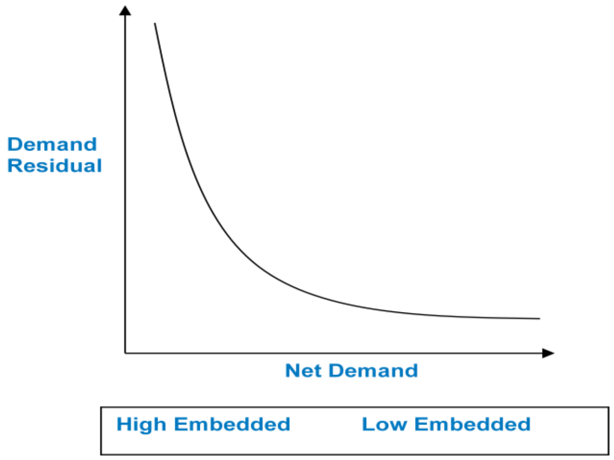
    a. Physical power flows: net flow onto and off the system

    b. Access to market: an embedded generator doesn't necessarily sell to the supplier at their GSP, but one at the other end of the country, therefore requiring the transmission system to transport this power to the point it is contractually required

    c. Security and quality of supply: frequency and voltage support

33. AW explained National Grid's views on how the TNUoS embedded benefit arises and how it could be considered to be equal to the summation of demand and generation residual elements of the wider TNUoS charge. The focus group discussed the relationship between GB net demand and the demand residual, highlighting that, if price controlled revenues remain constant, the lower the net demand the higher the demand residual will be. Hence increasing volumes of embedded generation will

offset a greater amount of demand reducing the overall net demand hence increasing the demand residual. This is shown graphically below.



34. One attendee asked what forecast of embedded generation was being used by the focus group. AW noted that the SO does not have full visibility of embedded generation which is a challenge for operating the system and in charging for use of the system; a Grid Code modification is looking into reviewing this (GC0042). However a view of future embedded generation levels will be presented in the National Grid report (see below).

35. One attendee commented that there needs to be a financial incentive on demand customers in order to drive a change in the demand pattern caused by consumer behaviour. It was questioned whether the basis of peak demand and Triads would need addressing and whether this sharpens signals.

36. AW explained that the focus group generally agreed that locational signals should be based on net flows, but that there was a difference in opinion as to whether demand should be charged on gross.

37. AW presented analysis comparing charges for transmission and distribution at a high level, however a direct comparison is difficult at a more detailed level. The focus group agreed to an extent that both transmission and distribution charges paid by generation users contain non-locational elements that serve for revenue recovery purposes; if these elements were of a similar magnitude then it could be argued that there would be a level of offset. It may be reasonable to consider transmission connected generation would pay TNUoS and embedded generation would pay distribution charges under the EDCM or CDCM methodologies.

38. AW presented focus group discussion on exporting GSPs:

    a. The focus group perception was that part of the embedded benefit was paid to an embedded generator to reflect the offset cost of transmission that was not required due to their existence. If a GSP was reinforced on the basis of export capacity, there was a majority view within the group that it was not correct for it to receive the embedded benefit.

    b. The focus group also felt that exporting GSPs needed addressing as they cause more constraints on the transmission system and increase GSP infrastructure reinforcement costs.

39. AW explained that following the review there could be a contained CUSC modification proposal to address some of the issues arising from the embedded benefit (this would have low to medium impact but wouldn’t resolve broader issues); or a broader review of the TNUoS embedded benefit). AW noted that the focus group had discussed the 132kV small generator discount applied in Scotland and no one

was strongly opposed to this being removed in 2016 (or some point in the future) providing appropriate transitional arrangements were in place.

40. AW explained the next steps would be for National Grid to publish a report later this month including the focus group discussions and presenting National Grid's view (or range of views). A CUSC modification proposal may be raised early 2014 in order to meet April 2016 implementation date.

6 Potential future modification topics – Adam Sims

41. The Chair took the attendees through the list of prioritised potential modification topics which was agreed by TCMF attendees in September 2013. **Action NG: It was agreed that it would be useful if some description was added to this slide as to what progress is being made on each.**

7 National Grid Website – All

42. National Grid's new corporate website went live on Monday 4th November 2013; attendees were asked for feedback on the charging pages of the website. One attendee commented that he does not want to see links to gas pages when he is looking at electricity related pages. One attendee commented that the new system is confusing in regards to publication dates and requires clear labelling of documents.

8 Next meeting

Next meeting: Wednesday 22nd January 2014
Time : 10:00 – 14:00

Venue : National Grid House Warwick

2014 Meeting Dates:

- Wednesday 19th March
- Tuesday 13th May
- Thursday 17th July
- Wednesday 17th September
- Wednesday 12th November