Meeting report

Meeting name	Transmission Charging Methodologies Forum
Date of meeting	13th May 2015
Time	11:00am – 3:00pm
Location	National Grid House, Warwick

Attendees

Name	Initials	Company
Wayne Mullins	WM	National Grid (Chair)
Juliette Richards	JR	National Grid (Technical Secretary)
Stuart Boyle	SB	National Grid (Presenter)
Andy Wainwright	WM	National Grid (Presenter)
Nick Pittarello	NP	National Grid (Presenter)
Garth Graham	GG	SSE
James Anderson	JA	Scottish Power
Bernard Kellas	BK	SSE
Joseph Underwood	JU	Drax
Mick Collister	MC	Infinis
Richard Mawdsley	RM	Haven Power
Jonathan Wisdom	JW	Npower
Vishnu Aggarwal	VA	Smartest Energy
Guy Nicholson	GN	Element Power
Tim Collins	TC	Centrica
Robert Longden	RL	Cornwall Energy
Sebastian Blake	SB	Open Energi
Alastair Martin	AM	Flexitricity
Edda Dirks	ED	OFGEM
Binoy Dharsi	BD	EDF
Fruzsina Kemenes	FK	RWE
Guy Phillips	GP	Eon
Colin Prestwich	CP	Smartest Energy
Peter Bolitho	PB	Waters Wye
Joseph Dunn	JD	Scottish Power Renewables

Dial In

Name	Initials	Company
Christoph Horbelt	CH	Dong Energy
Simon Holden	SH	LRSenergy
Jain Abhishek	JT	Tempus Energy

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 Ongoing modification proposals – Juliette Richards

1. Ongoing CUSC modification proposals were presented with updates for each.
2. With regards to CMP227, a question was raised as to what is the current G:D split? SB confirmed this as 23:77
3. JW asked about the impact of the potential extension to the implementation period of P272 and the impact this would have on demand charging. SB explained that CMP241 was written in such a way that if the implementation date for P272 is later than April 16, any parties that have transitioned during 15/16 would be treated as NHH but have the *option* to be treated as HH if they would like to, for the purpose of charging.

2 Extending the TNUoS tariff notice period – Juliette Richards / Stuart Boyle

4. JR presented slides to look at the potential impact of extending the TNUoS tariff notice period to 15 months. SB explained in further detail the consequences identified, and BD noted that EDF will be submitting a modification proposal to the CUSC panel in May to extend the TNUoS tariff notice period.
5. BK asked how long a new notice period might be. BD noted that the proposal to be submitted to the CUSC panel will suggest 'at least 15 months' but that the Workgroup will look at various possibilities.
6. An attendee asked that if National Grid carries the risk of TNUoS volatility under an extended notice period scenario, how much would the National Grid risk premium be? SB explained that rather than adding a risk premium, National Grid would bear the risk of any under / over recovery of revenues via TNUoS, and would look to finance this efficiently using the k mechanism to recover in a later year. So this is a financing cost rather than a risk premium.
7. TCMF attendees then discussed the importance of adhering to the €2.5/MWh limit for generation, noting that EU regulation overrides the CUSC. This would become more difficult under an extended notice period scenario due to the need to forecast further ahead. Attendees noted that a risk exists currently (of breaching the cap) as looked at for CMP 224 – an extended notice period simply increases this risk and the workgroup would need to discuss ways to minimise this.
8. JW noted that there is an element in DNO licences for mid-year tariff changes if necessary. As part of the Workgroup this will need to be considered. JW also noted that there was a transition arrangement in place for the implementation of the DCP178 change – with a notice period of 3m for the first year of implementation, rising to 15 months in the 2nd year.
9. GG discussed the 'principles' slide and noted that it may be difficult to clarify who has the most influence over a risk when trying to apply the first principle ('the party with most influence over an issue should carry the risk').
10. FK asked whether the TEC reduction period (for example) would need to increase under an extended notice period? WM noted that this is a possibility and would need to be considered further. JA mentioned that there may be an (unintended) impact around major investment for example generators deciding to close a year early in response.

3 User Commitment for Generator Focussed Anticipatory Investment – Wayne Mullins

11. WM introduced the User Commitment for GFAI slide, talking through 4 example scenarios.

12. GG noted that where special purpose vehicles are used, a 2nd generator in the appropriate scenarios can ‘walk away’ from a project at very little cost. This leaves the initial generator unwilling to take such a risk.

13. Attendees also discussed who holds the cost risk of Ofgem awarding, for example, 95% of the original cost – how would the 5% be split across parties? WM stated that National Grid’s view was that the efficient spend should be allocated on a MW basis, but this is something that would need to be covered in any future workgroup discussions, should a CUSC modification be raised.

14. The risk to a developer building GFAI (A) facilitating another developer’s project (B) was discussed. An attendee noted that mitigating the risk A faces through adequate User Commitment from B was an important factor in obtaining project financing. WM noted that based on stakeholder feedback, developer A is unlikely to be willing to finance the necessary oversizing for a competitor, even if this is for a short while – this would only happen if the expenditure could be made zero risk and accrued a greater rate of return than any other opportunity to use the money.

15. JW noted that only a cast iron guarantee between the 2 projects would ensure that neither consumers nor generator A ends up picking up the cost of any stranded assets.

4 BSUoS stability update – Nick Pittarello

16. NP introduced the BSUoS stability slides and re-capped the discussions from the March TCMF.

17. NP then asked attendees for their thoughts as to what the most appropriate timescales to fix BSUoS might be. Attendees discussed whether generator timescales might be different to suppliers’ –and whether a shorter time period (e.g. fixing BSUoS for a month) could lead to a smaller cash requirement for any stability fund option. JW noted that suppliers would prefer fixed charges for at least a year, particularly given that many 12 to 24m contracts are agreed 6 to 12months ahead. GG asked whether a month would be an appropriate timescale for generators, JU noted that a year to 18m may be preferable. GG noted that it would be helpful to look at the timings of other types of response payments.

18. Attendees then discussed whether there was a material advantage to industry holding a stability fund collectively rather than parties each setting aside cash themselves and effectively managing the risk individually in this way. It was felt this was difficult to clarify, and that a 3rd party product might have emerged if there was a clear advantage.

19. It was also felt that some parties may prefer to take the risk internally so would a future fund etc. be mandatory? If not, there may be unintended consequences for parties who find themselves as the ‘last man standing’ in any mechanism.

20. Attendees then discussed who should fund any future stability fund mechanism. GG noted that given that BSUoS is very impacted by SO activity around balancing, Ofgem may not countenance putting the cost on transmission owners. However JW noted that if the majority of BSUoS costs are caused by constraints, new connections etc. these are TO issues. Attendees also noted that TOs are likely to have the lowest cost of capital. All noted that it would be helpful to have some indication from Ofgem of their view early on and NP agreed to discuss this with Ofgem. The potential of an independent SO (with no assets to borrow against) was raised – this may well have a higher cost of capital than the TOs / be unable to leverage the amount of cash required. JW noted that if the fund was funded by BSUoS payers then they would be exposed to NG BSUoS forecasts and hence the commercial margin is replaced by a cashflow risk.

21. NP presented the risk margins slide. GG noted that if BSUoS was fixed for a period, this takes away the incentive to track BSUoS forecasts etc. – so this would be good

for new and smaller entrants to the market. Parties also discussed how to compare the cost of different options noting that you couldn't necessarily compare the risk margin on prices directly with the size of a potential fund. The cost of the latter would have to consider the cost of financing but also the opportunity cost of such funds. JA also considered the potential difficulties with regards to finance / audit if you are, for example, paid back from the fund a year later – in what year should this income fall?

22. BD raised a point about volume assumptions in the MBS, noting that one of the reasons for the seemingly poor performance of the NG year ahead BSUoS Price forecast was that National Grid was using demand volumes that were far too high. BD quoted that NG was using 630TWh (BSUoS charged to both supply and demand) rather than what would be a far more realistic 550-560TWh. It was suggested that there was need for National Grid to review the mechanism used to derive these volume assumptions. If they were adjusted for one or two parameters (in line with other forecasts) then the BSUoS price forecasts would be more accurate. NP noted that he would raise this with Iain McIntosh.

23. **POST MEETING NOTE**: NP has discussed this with the relevant parties who agreed this hasn't previously been an area of focus. It has been confirmed that 588TWh is now being used for BSUoS price forecasting but that underlying demand is going through a difficult and rapidly changing period. This is especially true with respect to the degree of returning demand following the recession, significant variability owing to embedded wind, and unprecedented recent growth in PV (est. at least 3GW in the last 3 months), making demand forecasting a real challenge at the moment.

24. NP asked whether there were any further issues for discussion. MC noted a focus on improved BSUoS forecasting would be helpful and another attendee questioned whether incentives could be developed for example for the TO to stick to outage plans. One attendee suggested a TO-type price control on BSUoS, and another improved SO-TO communication around outages.

5 Potential Charging Arrangements for exporting GSPs – Andy Wainwright

25. AW explained the drivers for this work, including stakeholder feedback from the previous review of transmission charging arrangements for embedded generation, the difference in treatment between sole use and shared assets, and the future operability of the system.

26. An attendee asked for clarification on slide 35 – AW confirmed that the peaks here are Triads and that this was not weather corrected but just metering data.

27. FK asked whether the difference in Scotland could be due to voltage differences / the difference in transmission definitions in Scotland. AW said this had not been assessed in detail, but believed that generally there was a greater penetration of embedded generation in Scotland and this would still be apparent even if voltage levels were similar.

28. Parties asked whether there were any plans to publish this analysis in more detail. It was noted that it may be valuable for the industry to understand where distributed generation could locate. AW noted that the intention is to break down the data by DNO area for the consultation after further discussing with DNOs.

29. It was asked whether a change to charging for exporting GSPs would require a DCUSA change and DNO licence changes. AW confirmed that this was potentially the case.

30. AW finished the presentation by inviting interested parties to further engage with himself. He also confirmed that there would be opportunity for attendees and industry parties to feed in their views, with a consultation hopefully being published in June.

6 Triad predictability – Andy Wainwright

31. AW introduced the Triad predictability slides, noting that this followed feedback from the DSR provider group. AW stressed that this was not intended to be a detailed review of Triad charging but rather to see if any incremental changes could be made to improve Triad predictability.

32. AW explained that National Grid had received feedback from stakeholders that the Triads were becoming more difficult to predict. This was due to an increased volume of demand responsive to the Triad, and also an increased penetration of embedded generation.

33. AW invited views as to whether Triad unpredictability was an issue for attendees, and whether attendees have ideas for improving the predictability of Triads. There was general support for the current Triad arrangements with several attendees noting that Triad predictability appeared appropriate at present.

34. Attendees then discussed the fact that with more parties moving to HH settlement, we should see greater Triad avoidance in future. However it was noted that some of these classes of customers may be unable to avoid Triads and there is a risk that cost falls on those who cannot move away (though this is potentially a social policy issue).

7 Update on CMP213 – Andy Wainwright

35. AW explained that the hearing date for the judicial review of CMP213 has been set for 1st and 2nd July 2015. However the judgement may not be handed down until after this date. After the judgement is handed down there is a 21 day window where appeal can be sought.

36. If there is no appeal on the judgement, in accordance with Section 15 of the CUSC (CMP240) there will be a 20 business day window for parties to reduce TEC without cancellation charge liability. All CUSC parties will be emailed 5 working days before this window opens. AW also provided an illustrative timeline of this process.

37. If there is an appeal, there will be an update at the September TCMF as to next steps.

8 TCMF moving forwards – Wayne Mullins

38. WM explained that in order to provide a forum for wider CUSC modifications that are not purely about charging, the intention is to run a CUSC Issues standing group adjacent to TCMF. Patrick Hynes will draft terms of reference for this new group, and it will have open membership and be chaired by National Grid.

9 AOB

39. One attendee asked whether there was any update on when Annual Load Factors (ALFs) would be available. WM will speak to SB to confirm the expected publication date – there will be an appeals window for this also.

40. **POST MEETING NOTE:** The expected publication date for Annual Load Factors has is currently November 2015.

10 Actions

The following actions are summarised from the text above:

I. A consultation on potential charging arrangements for exporting GSPs will be published shortly.

II. PH to draft terms of reference for a 'CUSC issues standing group' and will take these to a future CUSC panel.

11 Next meeting

Next meeting: **Wednesday 8th July**

Time : 11am

Venue : National Grid House Warwick