Minutes

Electricity Settlement Expert Group: Meeting 5

Minutes of the fifth electricity settlement expert group meeting.	By Date and time of meeting Location	Ofgem 10:00-15:00 1 October 2014 Ofgem

1. Welcome and introductions

1.1. Jonathan Amos (JA) welcomed the members of the group to the fifth meeting. Attendees are listed in Annex 1.

1.2. JA said that all materials for the meeting would be published on the website, here.

2. Review of minutes from meeting four

2.1. JA invited the group to comment on the minutes of the previous meeting before they were published. He said that Ofgem had already received comments on the minutes which were shown as tracked changes. The group was happy with the minutes.

2.2. JA went through the actions in the minutes. On action 2a, he said that although the DCC had given apologies for this meeting, they had indicated that there was no update to provide on consultations at this time. They would continue to provide updates when needed.

2.3. Action 2b would be addressed by the agenda item on correcting errors after the final reconciliation run. It would therefore be closed.

2.4. JA said that Ofgem was still reflecting on how they would proceed with work on Data Processing and Data Aggregation (DP and DA) functions; the action would be carried forward to the next meeting at which the group would be updated.

3. Detailed discussion on transition

3.1. FJ spoke to slides 4-16 on considerations for transitioning to new settlement arrangements. He asked if the group members had anything to add to the last discussion on the key issues which could affect the costs of the transition.

Costs

3.2. A member talked about the Change of Measurement Class process, stating that this is constrained by the existing registration system. He argued that centralisation of registration offered an opportunity to streamline this process, for example by scrapping proving tests for smaller consumers. A number of members agreed, one noting that if the process could be made more automated it would free up suppliers' staff to focus on resolving exceptions and improving the accuracy of settlement.

3.3. A member pointed out that the current Change of Measurement Class process had not been designed for and was not suitable for the mass transition of millions of sites, such as would be required here. Another member argued that a whole new Change of Measurement Class process was required. A different attendee agreed and said the process should be designed afresh. This member informed that this was being discussed at the

Performance Assurance Board and ELEXON had been tasked with coming back with proposals by the end of the year.

3.4. One member argued it would be desirable to design settlement arrangements that were independent of changes to registration. This would remove the potential dependency between the two reforms. However, other members said that they did not think this would be feasible.

3.5. A member argued that a more extended migration to any new arrangements would increase costs. This is because suppliers would need to manage a number of internal settlement-related systems concurrently during the transition period:

- one for consumers with traditional meters settled on the NHH arrangements
- one for consumers with smart meters settled on the NHH arrangements
- one for consumers with smart meters settled on the new HH arrangements.

3.6. Managing all these systems would be challenging for suppliers, particularly once a faster switching process is implemented. In addition there would be no reason to invest in the legacy system which could negatively affect its performance. As such, this member argued for a firm cut-off, by which all consumers with smart meters must be settled through the new arrangements. Related to this point a member argued that the earlier you bring forward the go-live date the better it would be for suppliers as it would give them more time to migrate consumers.

3.7. A member argued that lessons should be learnt from DCC go-live which allows flexibility over when suppliers enrol. In response a different member said the key learning was not to have a "soft launch" where you allow parties to move early without a fixed timetable. This member argued a firm timetable is required to give industry certainty.

Regulatory changes

3.8. FJ moved the discussion onto the changes to the regulatory environment required to deliver new HH arrangements.

3.9. An attendee commented that interim targets would need to relate just to the proportion of smart meters settled on HH data: this would avoid imposing de facto smart meter roll-out targets.

3.10. An attendee raised the possibility of cross-code conflicts between the Smart Energy Code (SEC) and the Balancing and Settlement Code (BSC) which could mean that by following one code, parties would be in breach of the other. He noted that parties would need to provide DCC with an estimate of the number of service requests they will issue each year. Should they breach this estimate significantly they could be suspended from using the DCC which could affect their ability obtain and process HH data which could cause them to be in breach of the BSC. This member called for coordination between codes to ensure such a situation would not arise.

3.11. Another attendee stated that Ofgem needed to consider the impact on the Data Transfer Network (DTN) of using HH data in settlement. He argued that the impact assessment would need to include assumptions on the volume of data transferring across the DTN and how often it is used. This attendee also said that use of the DTN is governed by the Data Transfer Service Agreement and this would need to be updated.

3.12. Also commenting on the DTN, a member said that some capacity would be freed up from data flows relating to NHH settlement not being used. Other members said that while this would release some capacity into the system, it would not make a significant dent in traffic since NHH flows are aggregated.

3.13. JA said the impact of using HH data on the DTN would need to be assessed, particularly if current services are not appropriate for HH data from smart meters.

3.14. Another member argued that there should be a technical review of the DTN. This attendee argued that the technology was twenty years old and as such the file sizes were very large and there could be more efficient ways to send settlement data between parties. Another attendee agreed, arguing that industry should consider what would be required in the future for transferring settlement data and what this would cost using the latest technology, rather than trying to fit existing systems around what will be required in the future.

3.15. Closing the discussion on regulatory changes, several members suggested changes to other codes that may be required: DCUSA transmission charging may be affected; there were also big changes being made to gas codes that could affect dual fuel suppliers.

Concurrent regulatory reforms

3.16. FJ spoke to slide 14 which summarised other regulatory reforms on the horizon to help explore the challenges suppliers would face at the time settlement reform would occur. FJ asked the group if the diagram was accurate and what the impact of concurrent reforms would be on suppliers.

3.17. One member said that the reduction in the number of other reforms towards 2020 implied by the diagram was based on what was known today, and was therefore not guaranteed, since there would always be new projects moving onto the agenda.

3.18. An attendee said that DECC would review suppliers' EMR obligations in 2016 and 2017 and this would impact on suppliers' billing systems. Other attendees also said that EMR would affect data aggregation.

3.19. Another attendee said that European reforms were missing from the diagram. In particular, the Demand Connection Code would affect the wholesale market.

3.20. One member said that the market investigation by the Competition and Markets Authority was important and could have significant implications for the industry.

3.21. JA thanked the group for their comments on the diagram and said that Ofgem would update it accordingly, however it would be difficult to give too much detail within each reform area. The group agreed the current level of detail was right.

3.22. FJ spoke to slide 16 informing that Ofgem wanted to understand how other industry reforms would affect the systems which suppliers would need to update as a result of settlement reform.

3.23. One attendee said that customer contract management systems needed to be added to the list of systems which would be affected by multiple reforms. This attendee said that the systems which suppliers use to keep track of the contracts they hold with consumers would be affected by both settlement reforms and changes to switching and central registration.

3.24. Another member agreed and added that customer service systems (eg call centres) would come under pressure during the period of the mass smart meter roll-out. A move to settlement with HH data would potentially add to this pressure.

3.25. A member said that there would need to be arrangements in place for an agent of last resort to process data from customers with traditional meters when it is no longer economical for existing agents to serve these consumers.

3.26. Another attendee said that faster switching would require changes to the speed of a number of processes: settlement reform would do the same. Billing systems was an area suggested as a potential overlap here.

3.27. A different attendee said that exposing suppliers to actual consumption rather than demand profiles would have a significant impact on suppliers' risk management, including forecasting systems. This attendee commented that faster switching will affect demand forecasting because if the number of customers a supplier has shifts more quickly it is harder for them to forecast accurately. An attendee warned that if suppliers cannot hedge this risk they will have to price it into their bills. Attendees agreed that central registration could help to mitigate some of the risk arising from next day switching.

3.28. A member called for certainty on the rules for all systems before reform is implemented. He argued that building systems and then changing their requirements, potentially to take into account of other reforms, would result in inefficiencies.

3.29. An attendee said that the smart meter roll-out needs to reach a certain level of penetration before any transition to new HH arrangements can begin. He argued that suppliers will need to learn how to handle the data they get from these meters and the requirements this will place on them. For instance they will need to grow accustomed to, amongst other things, receiving data directly (rather than from Supplier Agents) and managing meter technical details.

3.30. JA thanked the group for their input and informed that Ofgem would consider what concurrent regulatory changes would mean for transition.

4. Correcting errors after the final settlement run

4.1. Jeremy Adams-Strump (JAS) introduced the topic and provided quantitative evidence on the total value of disputes, broken down by causes and the time taken to identify errors (slides 17-25, here).

4.2. He then asked the group for their views on where the responsibility for resolving errors lies, with suppliers or elsewhere.

4.3. One member suggested that there were many errors which were beyond the power of suppliers to identify and correct. In particular this related to incorrect commissioning of current transformers (CT). They often inherited errors upon gaining customers that they had limited ability to identify. Another member agreed but said that the supplier had a responsibility for fixing the error if and when they became aware of it.

4.4. The conclusion of the group was that some errors are the responsibility of suppliers, and others are not. One member suggested that ideally a disputes mechanism should come to a qualitative judgement on the responsibility for the error, as well as the quantitative judgement on the materiality of it.

4.5. There was a discussion around the materiality of the total volume of disputes. One member suggested that it amounted to around one percent of the total imbalance market, which itself was around five percent of total demand. A different member argued that for an individual supplier on the receiving end of a large error, these values would be material, insofar as it would be worthwhile pursuing in court if there were not a disputes mechanism.

4.6. A group member argued that a situation sometimes occurred where a supplier would raise a dispute to correct for an error that negatively affected themselves, albeit only slightly. The member argued that the use of the dispute mechanism in such cases was an abuse of the system and could cost more in administration, paid for by everyone, than the value of the error justified. Such situations should be avoided, for example by means of an appropriate materiality threshold.

4.7. JAS asked about what drove the different timescales for identifying errors, for example why some took more than 14 months to resolve. Several members said that certain sites had very erratic consumption patterns, which complicated identification. JAS also cited a one-off review by a distribution company of HH sites, which uncovered a large number of errors.

4.8. JAS asked about the role of smart meters in allowing errors to be resolved earlier. One member said that they would help to an extent but that the difference would not be material. The errors associated with the current HH meters would remain. One group member suggested that there were some errors, for example relating to manual interventions that go wrong, that would always occur including with smart meters. However, another member said that the process errors arising from preparing consumption data for settlement (eg calculating EACs) in the current NHH market would be eliminated.

4.9. The point was made that other jurisdictions with smart meters continue to have mechanisms for adjusting for errors after final settlement, indicating that a significant number remain even once smart metering is rolled out. It was also pointed out that smart meters themselves were an unknown factor and could lead to new types of errors.

4.10. One member suggested that an option for resolving errors would be a mutual insurance approach. Suppliers would all pay a premium in proportion to their volumes and claims would be made against it by negatively affected parties when errors were identified. This would have the advantage of increasing financial certainty by reducing potential future liabilities, while still allowing material claims to be made. Several members agreed that in principle this could be a good solution. One member said that distribution companies may also wish to claim against such a scheme. JAS queried whether this would not diminish suppliers’ incentives to resolve errors.

4.11. Given that CVA errors appeared to come to light sooner, JAS asked the group whether the process for CVA adjustment needed to run on the same timetable as for SVA. One member said that he thought the reason that there was currently a single process and timetable was for the sake of simplicity.

4.12. JAS explained the options that were on the table (slide 27). One member said that in light of the above suggestion about an insurance scheme and the group’s interest in it, this should be a fourth option.

4.13. JAS asked the group to comment on the assessment of options (slide 28). One member reiterated the point about uncertainty around smart meters and said that the risk of material errors was enough to justify the mechanism’s continued existence.

4.14. One member said that the assessment may need to focus on understating the benefits of the status quo option: avoiding the recourse to litigation was important. However, he went on to suggest that there are weaknesses in the status quo that could be tweaked. For example, the threshold could be increased over time to incentivise errors to be resolved as soon as they are identified.

4.15. A different member responded that the downsides of financial uncertainty (caused by the status quo of not having a backstop) should not be underestimated. In his experience, this had proved a significant barrier to entry to the market for some firms.

4.16. Another member agreed and said that the energy industry was already viewed as extremely complex even without this additional financial uncertainty. For example, it was hard to explain why there was so much smearing of firms with errors that they were not responsible for. JA said that this issue was on the group's forward agenda under 'error allocation'.

4.17. One member suggested that the current arrangements of having a backstop at 28 months for an extra settlement run but no backstop for extra settlement determinations should be retained as an option. Someone else said that setting an appropriate threshold for materiality would be key here.

4.18. The group expressed the view that all options should be assessed as part of the impact assessment in the next stage of the project. JA closed the session and said that, as assessing this aspect of the market is difficult, Ofgem would appreciate suggestions on how to quantify costs and benefits of the different options. He suggested that members email thoughts after the meeting.

The group broke for lunch

5. Introductory discussion on reform packages

5.1. FJ introduced the topic (slides 32-34, here). He summarised Ofgem's understanding of what the group had concluded and asked if the group agreed with this summary: this would form the basis of an open letter at the end of the year. The group agreed with the summary.

5.2. One member queried whether distributional analysis would remain part of the assessment: this was something that the group had raised as being important, in addition to the costs. JA confirmed that the intention was still to undertake distributional analysis. The focus of this meeting however was on the costs, since this was where group members could best assist.

5.3. One group member asked if the changes that ELEXON was developing to the settlement timetable would be taken into account. JA said that Ofgem was aware of these changes and they could form part of the counterfactual for the IA.

5.4. FJ asked if the group thought that all combinations were feasible and should therefore be left on the table (slide 37). The group agreed with this suggestion.

5.5. One member said that a potential difficulty was trying to enact too many big changes at once: this is when problems could arise. It may therefore be better to make changes sequentially, in phases. For example changes to estimation could be made relatively soon.

5.6. However another member said that although concurrent changes added risk, it also made it easier to ensure that the benefits case for reform was delivered. He said that the costs of estimation would be linked to the decision on DPDA. JA said that Ofgem's thinking was to consider all changes holistically in order to understand the overall cost-benefit case for using HH data.

5.7. FJ explained Ofgem's proposed approach to cost assessment (slide 38) and asked the group if they thought it was feasible and proportionate.

5.8. One member said that it would be important for Ofgem to be clear on what it was requesting of firms, in particular around a set of assumptions on which to generate cost estimates. This could include variable assumptions. JA said that Ofgem had shared its assumptions for this stage of the project, but that list would require further updating for the next stage.

5.9. It was suggested that smart roll-out and potential scenarios around delays could be important here. However the DCC's performance could be assumed to match its targets.

5.10. One member said that it would be important to capture the differences between firms' business models. For example there would be a big difference in impacts on suppliers that trade power close to real-time and those that contract further ahead. A different member said that it was important for firms to provide justification and explanation around their cost estimates, including their confidence in them. Another member agreed with this point.

5.11. One member pointed out that firms had had difficulty in supplying ELEXON with costs relating to settlement timetable changes in the past.

5.12. Regarding the burden on firms, one member said that settlement reforms would be challenging to cost, given the number of options on the table. Another member said that it was necessary to give firms sufficient notice of a request, to enable them to set aside internal resource for it. Previous requests had given firms three weeks to respond, which proved difficult and would not be enough for this project.

5.13. FJ moved the discussion on to interdependencies between options that may need to be captured in cost estimates (slide 39).

5.14. A group member said that the central agent estimate would incorporate the capex of setting up new estimation systems – such costs would be hard to split out from the investment in other functions. However, they could possibly be extrapolated from the estimates from Supplier Agents.

5.15. One member suggested that one of the key interactions was between transition – in particular the duration of the migration stage where both NHH and HH systems would be run in parallel – and the other options.

5.16. A different member suggested that estimation and timetable options would be more marginal to suppliers' costs. The core operating costs to suppliers would stem from using HH data. The option areas that would be most material for suppliers would be the DPDA model and the timing of transition. DPDA options needed to be costed by suppliers because of the potential need to interface with a central agent. Another member agreed that it was the volume of data associated with interval settlement and the consequent changes to the supply business that would drive costs.

5.17. JA said that the IA should focus on such 'swing factors' that would be most critical to the business case for settlement with HH data. As such it would be good to explore these further with the group at a future meeting.

5.18. FJ asked the group if they thought that it would be a good idea to discuss specific cost categories at the next meeting. They agreed that it would be. One member added that from experience, such data requests worked best when the costs for each party could be fully identified, rather than leaving it open-ended.

5.19. JA said that Ofgem could lead a discussion on assumptions that would underpin the impact assessment. He said that the group could also discuss again the 'swing factors' relating to costs. The group agreed that these could both be useful.

Action: Ofgem

6. Wrap up and close

6.1. JA thanked members for attending and closed the meeting, noting that the next meeting would be held on 23 October at Mary Sumner House, Westminster.

Annex 1 – Attendees and apologies

Group members

Jonathan Amos (Chair)	Ofgem
Andrew Bard	MRASCO
Andy Colley	SSE
David Crossman	Haven Power
Eric Graham	TMA
Harish Mistry (morning only)	EDF
John Christopher (observer, morning only)	DECC
John Lawton	ENW
Jonathan Windeatt	Flow Energy
Kevin Spencer	Elexon
Mark Bellman	Scottish Power
Paul Akrill	IMServ
Paul Pettitt	Electralink
Sara Bell	UKDRA
Simon Bevis	Utilita
Stephanie Shepherd	Npower
Tabish Khan	British Gas
Tryfon Tzelis	E.ON

Ofgem attendees:

Francis Jackson

Jeremy Adams-Strump

Apologies:

Chris Alexander	Citizens Advice
Jonathan Bennett	DCC
Robert McNamara	TechUK
Tony Diccico	ETI

Annex 2 – Summary of actions

Agenda Item/ Action number	Action	Owner	Due by /Status
2	**Review of minutes from meeting four**		
	a) DCC to keep the group updated on DCC consultations and any changes to the DCC performance measures.	DCC	Ongoing
	b) Ofgem to reflect on discussion and update the group on next steps on data processing and data aggregation.	Ofgem	23 October meeting
5	**Reform packages**		
	a) Ofgem to revert to the group for further discussion on this topic.	Ofgem	23 October meeting