Minutes

Electricity Settlement Expert Group: Meeting 2

Minutes of the second electricity settlement expert group meeting.	By Date and time of meeting Location	Ofgem 10:00-15:00 10 July 2014 Westminster Central Hall

1. Welcome and introductions

1.1. Jonathan Amos (JA) welcomed the members of the group to the second 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 one

2.1. JA invited the group to comment on the minutes of the previous meeting before they were published.

2.2. There was general agreement that the minutes were an accurate account of the meeting. One member said that the tone could be made to better reflect the enthusiasm of the group for the project's goal of moving to settlement using actual half-hourly (HH) data. Another member said that they agreed but said that the minutes should also recognise the group's qualifications and concerns which had been raised.

2.3. JA said that the minutes of the Roundtable of Views agenda item would be amended to better reflect the positive tone of the discussion, whilst retaining a full account of the group's concerns. The minutes would be published on Ofgem's website, here.

Action: Ofgem

2.4. JA updated the group on the actions from the previous meeting.

2.5. Ofgem had made contact with the Irish energy regulator, the Council for Energy Regulation (CER). CER was open to presenting at a future meeting but had been unable to make this meeting. Ofgem would carry forward the action.

2.6. JA said that the drafting around manual processes in the terms of reference document, here, had been amended in light of comments from the group. He closed the action.

2.7. He said that the actions relating to the changes to the analytical framework would be discussed under agenda item 7.

2.8. The remaining actions related to the work on the settlement timetable: the DCC would present on their performance standards as agreed (item 4); Ofgem had approached suppliers to gather evidence as agreed (to be presented in item 4); and ELEXON had gathered further evidence and developed options as agreed (items 4 and 5). JA closed all these actions.

3. Introduction to discussion on settlement timetable

3.1. Kevin Spencer (KS) presented an introduction to the discussion on the settlement timetable (slides 2-6, here), recapping the points raised at the first meeting.

3.2. On slide 2, one group member pointed out that the performance standards related to different outputs for HH and non-half-hourly (NHH) meters. The former required 48 daily reads for the whole period that the standard applied to; the latter only required one meter advance for that period.

3.3. There was a discussion around the issue of costs incurred by having shorter timescales. One member said the costs should not be looked at through the lens of the current HH market – obtaining consumption data from smart meters would be very different with fewer communication disruptions. Another member said that the greatest costs would come from the need to send out agents to meter sites to collect actual readings in some circumstances, for example if there is no smart meter installed. KS said that this would be discussed further in the assessment of options, agenda item 5.

4. Evidence to inform the discussion on settlement timetable

Utilita - Simon Bevis (SB)

4.1. SB presented evidence from Utilita's experience over the last year of data retrieval from smart and advanced meter sites (slides here).

4.2. One member asked if the 90 per cent figure for performance at R1 included sites which could not be remotely read, in which case the percentage for remote sites would be higher. SB confirmed that this was the case. KS said that ELEXON's experience with remotely-read sites in the profiling sample was similar in terms of data retrieval rates.

4.3. A group member asked if Utilita needed to physically reset communications settings on meters for sites where communications were down for a sustained period. SB said that the number of site re-visits was low because customers were able to vend meters lacking communications by manually entering a code.

4.4. SB explained that one of Utilita's early experiences was that when a number of meters woke up and connected simultaneously the system could overload and fail to collect all readings. A group member asked if it was Utilita's systems or the mobile network which had overloaded. SB explained that the issue here was a combination of internal system load but also the stress on the network in the locality of the meter point(s). Utilita had learnt from this experience and had randomised the 'wake up' pattern to avoid overloading the system. SB said that while the randomisation has helped, this will prove an issue again once a larger number of meters are rolled out over the next few years.

4.5. There was a discussion about the meters that consistently had intermittent or no communications coverage. SB said that some of this population were consistently without communications month after month; however other meters would have coverage for a time and then drop out. It was not the case that one type of meter was causing the problems since Utilita's meters were all of the same type.

4.6. SB clarified that when communications returned to a site which had dropped out, Utilita could theoretically recover the missing days' snapshots and HH period data, but did not do so as it was not necessary for the purposes of settlement at present.

4.7. A group member asked if communications performance was linked to weather events. SB said that he had not analysed this so could not comment. Another member said that in their experience snow and flooding caused problems.

4.8. One member asked if the meters could use a variety of network providers. SB said that Utilita currently chooses from 10 networks with their SMETS meters, which lock onto the best signal in that locality and use that network. SB said that his understanding was that under the DCC these options will be limited, which would affect performance. Based on their current experience they are seeing 3-5 per cent of meters drop out of coverage. With fewer networks to choose from it would appear that there may be additional issues here.

4.9. With regard to roaming SIMs in AMR meters, Utilita found that these gave a much more reliable connection to the meter and this has helped to improve the percentage of data retrieved successfully from the AMR meter population. The meters with persistent failed connection tend to be the older meters which were originally installed with network-specific SIMs.

4.10. There was a discussion around how representative Utilita's sample was of the national picture. SB said that Utilita do specifically pick *localities* which currently have communications coverage but that there is a proportion where coverage is not then available at the *meter point*. He said that this was crucial when understanding the DCC's 99 percent coverage commitment. Clarity was required around whether it was 99 percent in a locality or 99 percent at meter points.

4.11. SB went on to say that Utilita operates in all GSP groups with the exception of Northern Scotland and Southern Wales. They operate in large cities where they would expect strong signal and are still seeing performance issues. He would expect that if there are performance issues in the large cities then there would be an increased proportion of issues throughout the rest of the country. He said that the challenge for the DCC is to resolve these issues across both urban and rural areas.

4.12. One member asked if the evidence suggested to SB that an interim settlement run was useful for identifying errors. SB said that yes, an interim run at one month or later would help. Only after around a month could problems be identified as persistent.

British Gas - Tabish Khan (TK)

4.13. TK presented on British Gas' (BG) experience to date with using SMETS meters. He said that BG had reached its one millionth installation. This figure included both 'SMETS-capable' (which had remote communications but whose pre-payment mode had yet to be enabled) and advanced domestic meters. BG had targeted installs with a greater chance of a successful installation; as such they had deferred replacement of pre-payment meters (PPM) with smart meters, and those in high-rise buildings and sites with inaccessible gas meters, until a later date when such an installation would be possible

4.14. BG had deferred smart PPM roll-out because they wanted to make sure they got it right. They did not think that it was acceptable for customers to have to manually enter codes into meters except as a last resort. BG has now started installing smart meters with activated prepayment functionality as a trial and will scale up soon.

4.15. BG had identified several issues with operating smart meters that they have now overcome. This included when customers left BG and later returned. In such circumstances, the meters would send BG the data from the period when it was not the contracted supplier. It would breach data protection rules if BG received this. BG has found a solution to prevent such data transfers.

4.16. There is also now a solution around interoperability when a customer leaves BG. They have developed a solution with CGI such that the meter could continue to be smart with the new supplier, if the latter chose this option.

4.17. BG had encountered various causes of intermittency of communications. For example random occurrences such as a bike placed next to communications hubs and lorries parked outside the house may block the signal.

4.18. TK said that the time taken to resolve communication issues with meters would depend on the read frequency. At present nearly 100 per cent of meters had been successfully read within a week of install.

4.19. Once an issue has been identified it can take up to six weeks to get an engineer on site. BG expect that this may take up to three months once mass roll-out begins as there will be greater demand for smart energy experts (engineers) across the country.

4.20. More than 80 per cent of BG's customers had opted in to half-hourly readings. These customers have incentives to opt in to obtain greater detail on their consumption in BG's 'smart energy report'.

4.21. At present BG is not submitting HH data into settlement. They have seen a reduction in *total* consumption for Profile Class 1 from the installation of smart meters but not a change in the *shape* of that consumption. The shape still reflected ELEXON's profile for this Profile Class.

4.22. BG had begun trialling free Saturdays and three-rate tariffs – households in the trial had smart appliances such as washing machines. In order to capture the settlement benefits for these sites, they had used different Time Pattern Regimes (TPR) and Standard Settlement Configurations (SSC). BG considers that the majority of the benefit of load shifting within settlement can be achieved using TPRs and SSCs.

4.23. A group member asked what behaviour changes BG had seen. TK said that they had seen a reduction in consumption for sites in line with the DECC impact assessment for the roll-out of smart metering.

4.24. TK said that he was in favour of strong performance standards but that there needed to be options to resolve issues after the final settlement run, assuming the latter is brought forward: even with smart meters electricity theft and crossed meters do occur.

4.25. TK said that if a site has persistent communications problems and it cannot be resolved by a re-install then the smart meter is left installed because the customer would still benefit from having the in-home display (IHD).

DCC – Jonathan Bennett (JB)

4.26. JB presented on the DCC's performance standards (slides here).

4.27. A group member asked for clarification around the meaning of 'Minimum Service Levels' on slide 3. JB clarified that 'Target Service Levels' and 'Minimum Service Levels' are thresholds in Service Provider contracts which result in the application of downside performance incentives and at certain thresholds enable DCC to invoke additional contractual remedies.

4.28. JB explained that there were various targets for different commands that sit below the highest level targets on slide 3. He said that the settlement project would need to look at the appropriate mix of commands required. He agreed to explore the opportunity to circulate the DCC's SLAs for different commands to the group.

Action: DCC

4.29. On slide 4 one member asked if the implication was that a small number of sites (less than one percent) would *never* have WAN coverage. JB said that it would be necessary to look at the proportionality of the costs of closing that gap.

4.30. Picking up on SB's point about the difference in coverage between localities and meter points, above, one member asked where the coverage would be measured. JB said that this along with other details would be spelt out in the Service Exemption Statement to be published in September this year.

4.31. JB said that he would keep the group updated on DCC's consultations and any changes to the DCC's performance measures.

Action: DCC

4.32. One member asked if DCC had targets relating to intermittency of communications: JB said that he was not aware of specific targets relating to intermittency but that this would be logically addressed under the DCC and underlying Service Provider performance measures.

ELEXON – Jonathan Priestley (JP)

4.33. JP presented evidence on settlement timings in other jurisdictions, focussing on those with smart meters and interval settlement (slides 8-10, here).

4.34. Group members asked what proportion of consumption was settled on interval data for the markets with shorter timings for final runs. JP took an action to investigate further.

Action: ELEXON

4.35. One group member said that an important consideration was the degree of smart meter penetration in these markets. JP said that he believed it to be high in all markets.

4.36. Another member said that it would be interesting to know why some had interim runs and others did not. One member commented that it appeared that all markets with interim runs also had an early first run, for example three working days (3WD) for California.

4.37. One member said that in the GB context, less than 5WD for the information run (II) would be a problem for identifying and resolving GSP metering faults.

5. Detailed discussion on settlement timetable

5.1. JP presented ELEXON's work on options (slides 11-20, here). He presented each option and its pros and cons, and the group discussed each option in turn.

Option One

5.2. JP presented option one (slide 14).

5.3. One group member asked if in addition to looking at pros and cons of each option, they could be ranked or scored against one another. KS said that this had proved difficult as there were nuances to each of the criteria. JA said that the plan was not to do scorings and weights at this stage. However, a more comparative assessment could be picked up in the next iteration. He said Ofgem would keep the need for this under review as options are developed and assessed.

5.4. Another member asked whether the options were to be assessed against each other or against a baseline. JA confirmed that the evaluation for this phase was comparative: options were to be assessed against one another.

5.5. One member asked about the consumer benefits of shortening the settlement timetable. JA said that this had been indicated at a high level in the Launch Statement for the project.

5.6. One group member said the risk of having a shorter timetable was that more disputes could be raised to adjust volumes after the final settlement run, which adds cost. Another member suggested that the important consideration was initial settlement being as early as possible for the purposes of reducing credit cover.

5.7. A different member said that there may be diminishing returns to increasing the speed of the runs: there may be a point at which there were no further benefits from faster runs.

Option Two

5.8. JP presented option two (slide 15).

5.9. One group member asked about the benefits of reducing credit cover by bringing forward the first settlement run to 5WD. JP said that a simplified calculation suggests that this move could reduce credit cover to 25 per cent of current levels. A group member noted that the overall reduction in credit cover would likely be less significant, one factor being the increased volatility in credit positions if they are calculated over a shorter period.

5.10. KS said that ELEXON had not worked up options of bringing the first settlement run forward by different amounts. He added that this option potentially had the most risks and difficulties for implementation.

5.11. One group member queried why bringing forward the first settlement would increase capital costs. In his view, this would reduce costs by lowering the amount of collateral that suppliers post with ELEXON. KS explained that 'capital costs' related to developing new central systems. JA clarified that the benefits from lowering collateral requirements were captured by the speed criterion.

Option Three

5.12. JP presented option three (slide 16).

5.13. One group member said that the downside to option three was that it had lost the benefit of the early first settlement run in option two. They proposed an additional option with: 3/4 WD for an information run, 5/6WD for the first settlement run, 15 WD for the second settlement run (if needed) and three months for the last settlement run. He said that 3WD should be sufficient for identifying large GSP metering errors, which is one of the main reasons for the information run.

5.14. JA said that this option could give a different outcome from the four options on the table, and so it was worth considering.

Option Four

5.15. JP presented option four (slide 17).

5.16. One member suggested that a five month gap between two runs was too long. Another member suggested that this gap could be reduced by having an interim run at three months.

5.17. One member said that the group had to recognise – and Utilita's evidence had supported this – that there were real time requirements for fixing errors once they were identified. As such they proposed modifying option four to bring forward the information run and first settlement run (to 5WD) but keeping the last settlement run at six months. They said that this would be a balance of ambition and data quality.

5.18. One member said that the costs of the information run were low. There was little to be gained by collapsing it into the first settlement run. However, someone else said that that would depend on the DP/DA model that was ultimately chosen: the costs of information runs would depend on the number of data hand-offs.

5.19. One member asked ELEXON if the current timetable was driven by the time requirement to calculate profiles. KS said that profiles were calculated the following day. However there was a rarely-used objection window for suppliers following the calculations. The group member suggested this window would not be required if customers are settled using HH data, thereby presenting an opportunity to shorten the timetable.

5.20. JA said that it may be worth exploring the option of shortening the current timetable for activities that happen before the first settlement run, such as aggregation of consumption data. This could include allowing only one day for these activities.

The group broke for lunch

The final settlement run

5.21. JP resumed the discussion of options. He first asked the group when they thought final run should happen. One member said that it may be a good idea to have it at six months initially but to put in place a timetable to review it with the long term view of bringing it in to 3/4 months.

5.22. One member said there may need to be a different procedure for disputes; another said that most disputes were caused by current transformers (CTs) and there may need to be different rules for them.

5.23. The group agreed that the options for the last settlement run should be three months, six months and six months but keeping it under review.

The information run and first settlement run

5.24. JP moved the discussion on to options for the initial runs.

5.25. One member said that they proposed the information run at 3WD and the first settlement run at 5WD. Two other members proposed an alternative of having 10WD for the first settlement run. They said that this would still give the credit cover benefit whilst being better for Central Volume Allocation (CVA).

5.26. Another member agreed that this option was more palatable for CVA. A third member agreed and said that there were extreme scenarios such as GSP metering faults in the Highlands which would need additional time to fix.

5.27. JP asked if the group was therefore agreed that 3WD for the information run and 10WD for the first settlement run seemed the best option: the group agreed.

Interim runs

5.28. JP moved the discussion on to interim runs. The group focused on when an interim run should occur if the final run happens at six months. One member questioned the benefits that an interim run at 15WD would bring. They said that three months would bring it closer to the last settlement run (at six months) and still allow problems to be resolved. However, another member said that there was volatility between 10WD and three months and so an earlier second run would be beneficial.

5.29. One member said that extra interim runs were not expensive and so more than one interim run could be considered. However, another member disagreed, pointing out that there were IT overheads for each run.

5.30. One member said that having the second settlement run at three months would fit in better with existing systems. Another member said that to bring it forward would have implications for the current HH market, which has the second settlement run at two months.

5.31. One member said that options leading to more manual downloads would have cost implications for suppliers. They said that three months may therefore be better, especially if the DCC falls short of its stated performance targets for the speed of data retrieval and connectivity.

5.32. One group member pointed out that it was important to be precise with terminology – was one month equal to 20WD for example? It was also important to know what that date meant in practice: was it the point of the invoice being paid or the volumes calculated?

5.33. JA said that ELEXON would revert to the group with a shortlist but the group had arrived at broadly three options for the timing of runs: 1) information run at 3WD, the first settlement run at 10WD, the second run at one month and the last run at three months; 2) information run at 3WD, the first settlement run at 10 WD, the second run at one month and the last run at six months; and 3) information run at 3WD, the first settlement run at 10 WD, the second run at three months and the last run at six months.

Action: ELEXON

Changes after last run

5.34. JP presented slide 19.

5.35. One member said that the big uncertainty was around the new cash-out arrangements leading to much higher prices and therefore more interest in correcting volume error. He said that in this context having no further runs could give rise to costly arbitration actions. Another member said that they would prefer the fully controlled and transparent process of an extra settlement run to a financial adjustment. There was general agreement around this point.

5.36. JP said that the downside to extra runs was the danger of their becoming institutionalised. He asked for the group's views on the appropriate timing of extra runs.

5.37. One member suggested 28 months as the backstop for performing additional settlement runs with the intention to bring this forward over time if possible. There was general agreement around this suggestion, although one member said that they could not see why it could not be sooner. In response, another member said that sometimes issues in consumption data only came to light years later.

5.38. One member suggested having a threshold for using the extra run, as is the case in Texas.

6. Introductory discussion on data estimation

6.1. Francis Jackson (FJ) presented on data estimation (slides 8-19, here).

6.2. On the interactions and dependencies (slide 12), noting another interaction, one member said that currently a significant volume of microgeneration is not assigned to a Meter Point Administration Number (MPAN) and is not registered in settlement. They informed that sites with microgeneration capacity are deemed to export 50 per cent of the site's generation capacity. He said that as this export is unmetered and is inaccurately deemed it affects the overall accuracy of the settlement process. Given this he queried whether estimation of export should be included in the estimation work.

6.3. Another member agreed, saying that in HH settlement export is not estimated but it is in NHH and that this results in around 1GW spill. They argued that export should be defaulted to zero for settlement purposes until it can be properly metered. One member suggested that there should be an obligation to meter export upon installation of a smart meter. Another member said that tackling this issue was a key aspect of the smart metering roll-out. JA summarised that Ofgem was aware that there were a number of issues with settlement of export and these would be discussed separately at a later meeting of the expert group.

Action: Ofgem

Estimation options for consumers with traditional metering

6.4. FJ explained the various options for estimating consumption for consumers with traditional meters (slides 13-14).

6.5. On the option to freeze profiles (option two), one member explained that these could not remain frozen forever as this would affect the accuracy of settlement and so they would need to be updated at some point in time.

6.6. On option three, one member said that they would be concerned with any move to use estimates for volume (rather than meter readings) as it would create a mismatch between what suppliers are charged through settlement and what they bill customers for (ie a disparity between purchases and sales).

6.7. Also on option three, another member raised the issue that customers with smart meters will not share the same characteristics as those with traditional meters: there would be a fundamental inconsistency of using a sample drawn from a different population. Those with smart meters are more likely to shift their load from peak times. To address this, another member suggested that it would be necessary to identify the customers with smart meters who are on an unrestricted tariff and so consume energy as if they have a traditional meter. Another member agreed that such stratification of the sample by tariff type would make this option viable.

6.8. One member said that by using smart meter data there is the potential to make estimation more accurate. This is because the effect of weather on consumption is currently calculated at a national level; using smart data would mean that estimation could be far more sensitive to local differences in weather. Someone else argued that temperature has a greater impact on consumption than load shifting behaviour at present.

6.9. One member noted that profiles are currently updated annually but very little changes year on year. As such he advocated for freezing current profiles (option two), arguing that this would be the least costly option and would not result in significant inaccuracy. KS for ELEXON confirmed that freezing the profiles would not be expensive however the other parts of the profiling process – creating daily profile coefficients and calculating EACs and AAs – would represent an ongoing cost. One member asked if ELEXON could give a breakdown of the process steps and associated costs of the current profiling process. FJ said that he would work with ELEXON to produce a breakdown.

Action: Ofgem

6.10. One member said that it may be necessary to develop a solution similar to option three to estimate data for consumers *with* smart meters, regardless of what was done for traditionally metered customers. He therefore reconsidered his earlier support for option two, noting that if option three is pursued then it may not make economic sense to pursue different options for smart and traditional consumers. The group agreed that if using profiles generated from smart data was the preferred option for estimating data for consumers with smart meters then it may make economic sense to pursue this option for all consumers when HH consumption data is not available.

6.11. Another member supported this view and said that it was important to keep an open mind regarding the number of customers still on traditional meters by 2020: although the target was less than one percent, this may not be guaranteed. As such, it was important to find a solution that ensured the accuracy of estimation for these customers.

6.12. FJ asked the group if they thought that all the options on the table would be sufficiently accurate. One member said that either option one or two would be accurate, given that the profiles do not change dramatically year on year.

6.13. Another member noted that as the population of customers with traditional meters (as more get smart meters) gets smaller and smaller then errors will creep in.

6.14. One member argued that if more HH data is available due to the roll-out of smart metering it would be remiss not to use it for estimating consumption unless it is prohibitively expensive to do so. Someone else agreed and said that subject to suitable sampling techniques, smart meter data should be used.

6.15. JA summarised that no option was yet off the table however, subject to the discussion on estimation options for consumers with smart meters, the group may want to refine options.

Estimation options for customers with smart/advanced meters

6.16. FJ spoke through the options for estimating data for smart meters (slides 16-17).

6.17. One member queried whether option 6b would include weather correction for the frozen profiles. FJ informed that potentially that could be a further sub-option – the profile of last resort may be infrequently used and there was therefore a consideration of how accurate it needed to be.

6.18. One member advocated using option six, arguing that if site-specific data is available then it should be used as it would be the most accurate estimate. Another member agreed and said that this follows the process for estimating data for current HH sites when none is available, as set out in Balancing and Settlement Code Procedure (BSCP) 502. They informed that BSCP502 sets out a hierarchy of estimation methods where HH data is unavailable. However, they argued that BSCP502 would need to be adjusted to make it appropriate for domestic and smaller non-domestic sites.

6.19. One member informed that BSCP502 is undertaken manually and this can result in significant error. Commenting further, they said that it would be a considerable task to work through the BSCP and the various estimation methods. He argued that if it were to be appropriate for millions of sites it would need to be standardised and automated. Another member informed that it is already possible to create an algorithm to automate estimation following BSCP502; indeed his firm had done so.

6.20. On options four and 6a, one member raised concerns that using smart data to estimate consumption for customers with dynamic tariffs may be inaccurate. They argued that segmentation of customers would be required so that data from those with dynamic tariffs was used to estimate data for similar customers. Someone else said that as long as reconciliation gave enough time to replace estimates with actual data then the risk of inaccuracy should be contained.

6.21. JA summarised the outcome of the discussion: the group felt that historical site-specific data should be used first before resorting to profiles generated from smart data (option 6a). He asked whether creating the profiles would be costly. Someone argued it would not be as the HH consumption data would already be available and aggregated. Another member said that if the industry invested in such a solution for customers with smart meters then it could use it for those with traditional meters as well, making it more cost-effective.

6.22. One member agreed with the above comments, adding that there was an issue of fairness of applying the same methods to both types of customer.

6.23. One member argued that we should look at other countries where smart meters had been rolled out and settlement is based on interval data to see what method of estimation they use. FJ agreed that this would be a sensible approach and said that he would contact other jurisdictions to find out their approaches.

Action: Ofgem

6.24. FJ also informed that in Texas they use "like weather days" where data is missing. This means that rather than using the previous day or the same day from the previous week, they use the closest similar day to estimate consumption for each site.

6.25. One member raised the consideration of what would happen if there was a mass failure in the smart metering system. He argued that if this occurred there would be a need for a plan of last resort. One member informed that such a mass failure had occurred in HH settlement and BSCP502 was followed and it was effective. However, they cautioned that this might be because the consumers affected were non-domestic so their load was simpler to estimate.

6.26. JB said that the DCC would have to take into account how its systems would be critical for secondary processes such as estimation. This would affect its contingency planning.

6.27. JA queried how far the group needed to go in prescribing the solution for estimation. He reminded that the purpose of the group was to develop options with sufficient detail that they could be accurately costed during the detailed assessment stage and that the detailed design would follow afterwards. He suggested it was only necessary to set the principles of the estimation process. The group agreed with this approach. One member noted that this followed a similar approach to the Electricity Balancing Significant Code Review which did not design modifications exactly, but published business rules which set out the direction of travel.

6.28. FJ summarised that the discussion had been helpful input to Ofgem's decision on which options to shortlist. The group had coalesced around the notion of using site-specific data to estimate a site's consumption. Where this is unavailable, and for consumers with traditional metering, the group felt that the option of using data from smart meters to create profiles – providing it could be appropriately segmented so as to reflect the characteristics of different consumers – should be pursued. FJ he said that he would revert to the group with further information and a refined list of options at the next meeting.

Action: Ofgem

7. Update on analytical framework

7.1. JA presented the updates made to the analytical framework based on feedback received at the last meeting (slide 21, here) and closed the actions.

7.2. On the second bullet, relating to settlement's interaction with other market arrangements, one member asked what would happen if there were options that improved settlement but worsened network charging, for example.

7.3. JA said that all effects of a given option would be weighed up in the evaluation.

7.4. There was a discussion around the first bullet, the objective on forecasting. One member said that there needed to be an additional sentence, making it clear that settlement allocations should reflect actual demand as closely as possible, and that therefore suppliers would be incentivised to forecast for it. However there would still be some discrepancies between actual demand and allocation caused by smearing.

7.5. JA agreed and said that the objective would be modified to say that settlement allocations should reflect actual demand.

Action: Ofgem

8. Wrap up and close

8.1. JA thanked members for attending and closed the meeting, noting that the next meeting would be held on 31 July at Ofgem's offices.

Annex 1 – Attendees and apologies

Group members

Jonathan Amos (Chair)	Ofgem
Andy Colley	SSE
David Crossman	Haven power
Eric Graham	TMA
Harish Mistry	EDF
John Lawton	ENW
Jonathan Bennett	DCC
Kevin Spencer	Elexon
Mark Bellman	Scottish Power
Paul Akrill	IMServ
Paul Pettitt	Electralink
Rachael Burn	EON
Simon Bevis	Utilita
Stephanie Shepherd	Npower
Tabish Khan	British Gas
Tony Dicicco	ETI
Tony Thornton	MRASCO
Xander Fare	Tech UK
John Christopher (observer)	DECC

External presenter (attended part only):

Jonathan Priestly, ELEXON

Ofgem attendees:

Francis Jackson

Ciaran MacCann (attended part only)

Jeremy Adams-Strump (attended part only)

Apologies:

Richard Hall, Citizens Advice

Sara Bell, UKDRA

Steven Bradford, Flow Energy

Robert McNamara, TechUK

Hazel Ward, Npower

Annex 2 – Summary of actions

Agenda Item	Action	Responsible	Due by /Status
N/A carried forward	Ofgem to ask Ireland's energy regulator to present at a subsequent meeting.	Ofgem	Update by 31 July meeting
2	**Review of minutes from meeting one**		
	a) Amend minutes of meeting one to better reflect positive tone of the meeting whilst retaining a full account of the group's concerns.	Ofgem	Actioned
4	**Evidence to inform the discussion on settlement timetable**		
	a) DCC to explore the possibility of sharing with the group their SLAs for different data commands.	DCC	31 July meeting
	b) DCC to keep the group updated on DCC's consultations and any changes to the DCC's performance measures.	DCC	Ongoing
	c) ELEXON to add to international comparisons with information on performance in terms of amount of consumption settled using interval data over time.	ELEXON	Update by 31 July meeting
5	**Detailed discussion on settlement timetable**		
	a) ELEXON to revert to the group with a further refined list of options.	ELEXON	31 July meeting
6	**Introductory discussion on data estimation**		
	a) Ofgem to modify expert group's workplan to include future session on export.	Ofgem	31 July meeting
	b) Ofgem to work with ELEXON to present to the group a breakdown of steps in profiling process and associated costs.	Ofgem	31 July meeting
	c) Ofgem to examine in more detail estimation processes in other jurisdictions where consumers are settled on interval data.	Ofgem	31 July meeting
	d) Ofgem to revert to the group with a refined list of options for data estimation.	Ofgem	31 July meeting
7	**Update on analytical framework**		
	a) Ofgem to modify objective relating to forecasting in line with the group's comments.	Ofgem	31 July meeting