Power Responsive Steering Group
Note of Fourteenth Meeting

30 January 2019, 13:00-17:00 hrs, held at Elexon's offices, 350 Euston Rd, London NW1 3AW.
This note was prepared by Sustainability First on behalf of the Power Responsive Steering Group.

1. Welcome and introductions

Cathy McClay (Chair) welcomed steering group members, noting that the previous meeting on 3 October 2018 considered remaining barriers to entry and priority actions to take in the short, medium and long-term. From a long-list of issues, the discussion had focused on: the cost benefit proposition and value stacking from services; data availability and gathering; and code governance.

The January 2019 steering group began with an **update from National Grid ESO** and **policy & regulatory changes impacting demand side flexibility (DSF) from BEIS and Ofgem**. Discussions included: **supporting DSF providers through change and uncertainty from short to medium term;** and **future opportunities and evolving value characteristics of flexibility,** concluding with a summary of Power Responsive activities, and next steps.

2. Supporting demand side flexibility providers through change and uncertainty in the short to medium term

National Grid ESO, BEIS and Ofgem each summarised recent developments followed by discussion and feedback, particularly from DSF providers on: changes that are impacting DSF provision and why; and how to transition through this period of uncertainty.

2.1 National Grid ESO Update

Colm Murphy (National Grid ESO) highlighted three current areas of focus:

- **Legal Separation** – From April 2019, National Grid ESO will be a legally separate entity within the National Grid Group. They have begun the process with a three-month practice period, including physical separation, ring-fencing information and protocols for breaches.
- **Draft Forward Plan 2019-21** – sets out an enhanced role for National Grid ESO to facilitate competitive markets and unlock benefits for end consumers. Open for feedback until 14 February 2019. With a final version for consultation due in March 2019.
- **RIIO T2 2030 Vision** – a conversation has started about the range of costs for the ESO over the next price control and consumer benefits. Feedback will be sought on proposals from March 2019.

NG ESO Forward Plan Deliverables (financial year 2018-19) were outlined, including: a consultation event; new provider journey document (published December 2018); wider access to the balancing mechanism (BM) with aggregated BM Units, and an interim solution to enable participation in both the BM and Firm Frequency Response (FFR); EPEX (European Power Exchange) platform development, with full delivery in June/July 2019 for standardised products in week ahead auction; consideration of exclusivity clauses through the Energy Networks Association (ENA); and moving toward a competitive market for reactive power.

There was discussion about how changes to future markets for DSF could be made faster. There is a near-term risk that more actors could exit the market than enter. Cathy McClay noted that a full update on balancing and ancillary services is due shortly – covering what these will be and how they will be procured. The EPEX auction will go live in March 2019 with existing products – standardised versions of primary, secondary and high FFR products.

Frequency Control by Demand Management (FCDM) will come to an end, but there will be a new faster static FFR product from March 2019. A lot of modelling has been done on new dynamic FFR products, but they will need to be stress-tested by the control room before implementation – and due to operational complexity this could take upwards of a year.

DSF provider feedback

Aggregators welcomed the System Operability Framework (SOF) and technical workshops run by National Grid ESO. The fundamental challenge is that grid requirements are changing. This creates discontinuity for providers, who need forward views to be able to justify investment decisions and inform customers.

Redefining services based on system characteristics, rather than technologies, is useful. Aggregators do not need long contracts (where the ESO and customers take the risk), just better information and shared strategic thinking in system balancing. For example, it is unclear how much volume will be contracted for Project TERRE.

Clarity is critical. The Capacity Market (CM) near-term standstill and Targeted Charging Review (TCR) are the two biggest issues for DSF providers currently. There is a lot of difficult news at the moment. It is therefore very important that future value is signposted. The System Needs and Product Strategy (SNaPS) will ultimately help, giving information about future services. The guidance documents, Power Responsive workshops, and ESO Roadmaps are also great sources of information and a step in the right direction for supporting DSF providers.

The impact of extended timetables for product development was highlighted. Negative impacts of regulatory & policy uncertainty are being felt now, and new products which offer future value streams are taking time to develop. It is important to recognise the time required for aggregators to educate and inform end users on new markets and values.

End users noted that the move to standardised tenders was difficult initially but is ultimately helpful. Standard EFA blocks (Electricity Forward Agreement) are used in wholesale. A benefit of FCDM was bidding in for each settlement period, which was more like forecasting in wholesale, rather than ancillary services. The interim solution for FFR will be in EFA blocks.

2.2 Short-term policy & regulatory changes impacting demand side flexibility

Capacity Market

Charles Phillips (BEIS) gave an update on the Capacity Market. The European Court of Justice (ECJ) ruled in favour of Tempus Energy's case for a fossil fuel bias in UK power markets in November 2018. The ECJ called for a re-investigation of the process regarding state aid approval, leading to a standstill on payments.

The European Commission (EC) is re-investigating the original state aid application process. The EC is likely to give an opening decision and sense of direction in February 2019, followed by a second stage of investigation. The EC have not committed to a firm timeline for a reviewed decision on state aid, but are aware of the pressure for BEIS. BEIS do not see a capacity or security of supply challenge this winter, but next winter may be more challenging. BEIS seeks re-instatement of the CM and original state aid approval. They do not want to have to return to a supplemental balancing reserve.

In the event of re-approval of the CM, back payments can be made to those CM providers currently deprived of revenues due to the standstill in payments. BEIS plans to hold a T1 auction this summer on a contingent basis – this means capacity payments would not be made until state aid re-approval is granted. BEIS held a consultation in December 2018 on practical arrangements for the replacement of the T1 auction, recognising the uncertainties for remuneration and timetables of new build projects.

Customers pay a CM levy, which suppliers collect. The collection of this levy has currently been suspended. However, overwhelming feedback was that it would be better to continue to collect payments – through re-instatement of the ESC (Electricity Settlement Company) process or through BSC code modification. Ofgem needs to set a price cap shortly so there is some urgency to the decision to re-start collection of the customer charge by suppliers.

The EC has also appealed the ECJ judgement (lodged 25 Jan 2019). It is likely that the EC made the appeal because the judgment has wider ramifications of principle for the state aid process generally, potentially creating new obligations on the EC and materially affecting its workload. This development does not affect BEIS's steps toward CM re-instatement. The appeal will take a long time. It took four years for the ECJ judgement. If the EC wins the appeal, the legal position would be that the CM had state aid approval from the outset.

The CM 5-year review is due. There was a call for evidence in late 2018 and responses will be published shortly. A consultation on minor changes will follow but this is not the priority currently.

Steering Group members noted that a general working assumption is that the CM will be re-approved by the EC, but what happens if it is not? BEIS highlighted that the UK has the first CM scheme and many other countries have also introduced capacity schemes. Current EC guidelines for these mechanisms are close to / drawn from the UK CM. If the scheme were found to be problematic, this would have ramifications for capacity mechanisms across the EU.

BEIS update

Cost of energy review

David Capper (BEIS) gave an update on wider government initiatives relating to DSF. Greg Clark responded to Dieter Helm's Costs of Energy Review in a speech in November 2018 ('After the Trilemma'), which set out four principles for the power sector: markets; insurance; agility; and no free-riding. It is through this lens that the Secretary of State views all climate change and energy related proposals. A government White Paper is due by the summer.

It was noted that 'agility' is a synonym for 'smart / flexible'. There is a focus on system operation and operators – legal separation of the ESO role and development of regional system operators. There are two things government would like DNOs to do in the short term: open network requirements to market competition; and mitigate 'conflicts of interest' for DNOs as both procurers of services to fulfil network requirements and providers – for example through greater ring-fencing of activity. BEIS is prepared to intervene to mitigate conflicts of interest if necessary.

Four main areas for improvement were identified for 'agility':

- **Data to support market development** – a data taskforce has been set up, chaired by Laura Sandys, considering data collection, accessibility and governance, due to report summer 2019.
- **Code governance** – a review by Ofgem and government. Prepared to legislate if needed. Stakeholder workshops are scheduled for 4 & 18 February 2019.
- **Engineering standards** – whether technical specifications for the system need updating to reflect smart/flexibility.
- **Review of the supply market** – supply licence, the supplier hub model and future of supply ongoing.

Smart Systems and Flexibility Plan

BEIS put out a progress update to the plan in October 2018, indicating that 15 of the 29 actions have been completed and 9 new actions identified.

- **Removing barriers for smart technologies (storage)** – there has been a consultation of the planning framework for storage, particularly considering co-location with renewables (closes 25 March 2019).
- **Smart homes** – electric vehicle home charge points that benefit from a Government grant scheme will need to be smart from summer 2019. Going forward, all charge points will need to be smart. A high-level specification has been developed with more detail anticipated with secondary regulations for all charge points. There is an Electric Vehicle Energy Taskforce – to consider technical issues and regulations. A response has been published to the smart appliances consultation – which includes the ability to legislate on appliance standards, with different options depending on UK exit scenarios.
- **Markets for flexibility** – BEIS is consulting on the proposal for a Smart Export Guarantee to support market access for small-scale renewables.
- **Innovation competitions** – recent announcements: £20million for large-scale energy storage (4hr duration); and £4 million competition for flexibility exchange trials.

David Capper is changing roles to become Director of EU Energy and Climate in BEIS.

Ofgem update

Whole system

Nathan Macwhinnie (Ofgem) noted that a whole system amendment has been proposed for DNO licenses to mitigate the impact of actions on other parts of the network (consultation closes 11 February 2019). DNOs cannot own or operate storage (21 December 2018). Work continues on the treatment of storage as generation in licencing and how this sits with the TCR. Ofgem welcomes responses to the ESO DRAFT Forward plan, and these will be discussed at the next Smart Systems Forum.

Charging arrangements – future, residual and access
Jon Parker (Ofgem) explained that there are two Significant Code Reviews (SCR) covering the 'residual' and 'forward looking' components of charges:

- **Residual charges** – the consultation for the Targeted Charging Review closes on 4 February, with proposals for a move away from volumetric charges to either: a **fixed charge** or a **capacity charge**; and **removal of embedded benefits** for generators (covering 2 BSUoS benefits for small generators and the Transmission Generation Residual for larger generators). The aim is to reduce distortions, freeriding and 'get a fair outcome' overall for consumers. It was noted that under **BSUoS** (Balancing Use of System) smaller suppliers are offsetting charges. Ofgem is consulting on the implementation timetable for both residual charges (2021 or phased between 2021-23) and embedded benefits (2020/21).
- **Forward-looking charges –** the Access and Forward-Looking Charging SCR is considering how to improve forward signals in distribution and transmission charges, as well as other improvements to access arrangements. **DUoS** (Distribution Use of System): whether to change the balance between volumetric, time of use and capacity charges, and options to **improve locational signals** including potentially greater granularity for lower voltages. **TNUoS** (Transmission Network Use of System): whether large generators should pay regardless of location (i.e. there are currently credits in some areas), and whether the TRIAD approach is fit for purpose. **Access arrangements**: for example, potential improvements to flexible connections (such as caps on curtailment). This work is at an earlier stage than the TCR. Ofgem has set up a **delivery group** to help it develop options and a **challenge group** to question them. The likely timetable is: option development in 2019; consultation on 'minded to' options in spring 2020; direction to industry to develop modifications in autumn 2020; and implementation from 2022.

National Grid ESO chairs the BSUoS taskforce. Following the TCR, there was discussion on the taskforce scope – whether BSUoS is just a residual charge, or whether there are forward access charging elements; and if it is a residual charge whether it would be fixed or capacity charge. The taskforce will publish a DRAFT report in April 2019 and will consider whether there are forward looking elements to BSUoS.

DSF provider feedback

There was a strong steer from the group that although the long-term direction of travel is appropriate – to remove distortions in charging and promote greater cost reflection – the timing for TCR implementation was open to question. The residual and future charging elements interact, so staging the changes, with residual charging arrangements set first, then future charges – seemed unhelpful. The TCR dulls current signals, whilst access reform introduces a future facing signal. If introduction is poorly coordinated this opens a gap. Most DSF providers felt that the timescales for implementation of residual and future facing charges should be better aligned than currently proposed.

Some participants dispute the TCR impact assessment. Modelled benefits and impacts depend heavily on what's happening in the capacity market. With the current hiatus, it was suggested that a decision on TCR should not be taken until the situation on CM state aid re-approval is clear. Ofgem suggested that they have a lot of experience of modelling sensitive assumptions. Their judgements are also based on principles and not the cost-benefit of models alone.

DSF providers felt that the principles are broadly 'right' – but timing is not sufficiently thought through. Uncertainty is impacting investment today, whilst new markets are not coming fast enough. The CM hiatus and TCR are currently the biggest issues – leading to loss of confidence and investment – with customers backing off, banks pulling out of projects and renewable investors looking overseas. It's hard to make a DSF business case for the UK right now, compounded by Brexit.

There was some concern about the principle of no freeriding (from Greg Clark's speech), as it is possible to accuse anyone of getting a free ride. TRIAD management enables some customers to reduce their costs, whilst others pay more. This has effectively reduced demand at peak by 20%. But it is getting more difficult, which is inevitable as more people engage. One view was to stop focusing on the hypothetical non-smart customer picking up the bill, because it's holding everyone else back from making the transition to renewables and smart systems. Another view was that the distributional impacts should be understood more fully.

There are two different business models for transmission - versus distribution - connected generators. Changes in charging arrangements are designed to ensure the same treatment for all generators – to 'level the playing field', but it is also important to ensure that there is **equal access to markets for**

flexibility. Currently TRIAD avoidance gives higher financial benefit than contracted services – so it's important to resolve the disparity.

Industrial & Commercial (I&C) customer representatives suggested that in the TCR costs have been shifted from households to I&C customers, and that the impact assessment has not taken all factors into consideration. TRIAD avoidance might give a 4% peak response. But the approach on residual benefit has transferred a 9% benefit to households from I&C customers. There was discussion about whether the 2GW of benefit would be procured through the CM, but it was noted that not all DSR providers could access it. So what other network signals will be put in place? Separately, the distributional impacts on households of a fixed charge for residual charging also need to be understood. The effects will be felt most by low users, economy 7 customers, potentially vulnerable households, small businesses and those who have taken steps to reduce their electricity consumption.

A lot of suppliers have been promoting energy efficiency – but have found their customers frustrated that investments in energy efficiency – based on anticipated savings in moving from commodity to capacity costs – will not be realised. Regulated utility companies have set their price controls for 2019 with Ofwat – with no knowledge or foresight of TCR impacts – which means considerable losses. Public sector institutions (such as hospitals and local authorities) cannot make a business case for DSF if they can't get a return on investment.

A straw-poll of steering group members, found: none in favour of implementing the residual charge timetable as currently proposed; most supportive of reform but stressing the importance of getting the timing right and taking a whole system approach; and a few against reforms. The latter were concerned about the cumulative impact of changes on investor confidence. It was felt that a clearer vision is needed for charging reform and the implementation timetable – setting out how long it will take to achieve fully competitive markets, with charging reforms considered holistically rather than staged.

3 Future opportunities and evolving value characteristics of flexibility

3.1 Whole system operation, balancing and changing patterns of demand

Future system operation

Beth Warnock (National Grid ESO) gave an overview of the evolving needs of the system. This was initially outlined in the System Operability Framework (SOF). The work considers economic dispatch of generation to 2030, considering the difference between traditional 'synchronous generation' – such as gas and nuclear, which have large rotating parts in synch with network frequency – and 'non-synchronous generation' – such as renewable electricity which requires a converter to connect synchronously to the network.

Historically, the network has been designed for synchronous generation – which can offer benefits in terms of management of power quality: inertia, short circuit and dynamic voltage. Non-synchronous generation does not offer the same system benefit characteristics. So as the level of non-synchronous generation increases on the system issues may begin to arise in the 2020s, and there may be a growing opportunity for DSF providers to offer ancillary services. The approach to RoCoF (Rate of Change of Frequency) is currently masking these issues to some extent. Maintaining fault levels – to detect faults on the system – is becoming a major issue. At the moment bringing on a generator is the only method to solve short circuit levels.

National Grid ESO is looking ahead to identify potential issues early and develop ways to resolve the technical challenges of more renewables, ideally before they materialise. These tend to be Transmission issues but some issues are more regional and locational – depending on time of day / year. Knowing what we need is becoming more complex. National Grid ESO is taking a practical approach, through path-finding projects, which involve learning by doing – considering technical and market solutions, with a Network Development Road Map, building on the NOA (Network Operations Assessment) process.

It might be helpful to start an early conversation about principles by which future markets might solve technical problems. For example at the moment National Grid ESO buys MW to access MVars. Ideally they would prefer to buy MVars directly – so what are the underlying principles for developing a market in MVars? Inertia reacts instantly. Can procure synthetic inertia through FFR – but this involves seeing what's happening on the system then reacting. FFR may reduce the amount of inertia needed. A major challenge will be getting the information about system needs in a format so that customers could invest – this process has begun with SNaPS.

There was discussion about whether there is an identifiable level/threshold at which non-synchronous generation causes issues. Should there be a cap on the instantaneous amount of non-synchronous generation accepted on the system? For example, the Irish system is dealing with high levels of non-synchronous generation, so introduced a cap subject to RoCoF rates and put a roadmap in place. National Grid ESO noted that they must remain technology agnostic on future energy scenarios. Work will continue via the ESO Forward Work Plan. Availability of data will also be important for innovative solutions to come forward.

Regional & local system requirements

Roger Hey (Western Power Distribution) discussed opportunities and challenges for DNOs/DSOs. New markets need to be built around the physics. At a distribution level there is already changing system usage: 30GW distributed energy resources; 15GW solar photovoltaic; 8GW distribution-connected wind; and 178KW electric vehicles (EVs). DNOs have the Distribution System Operability Framework (DSOF). Operability is a growing issue. Electric Vehicles charging at 4,000KWh is the same as an average households demand (same for heat pump demand).

It is unclear what will happen to peak prices in the context of electrification of transport and heat. DNOs are considering what consumers are likely to want in future. Looking at the telecoms industry, customers may not just want volume but also speed: superfast and unlimited volume. Open Networks is looking at this in detail. The Future Worlds Consultation set out 5 scenarios. Short-term transmission and distribution interfaces have been considered through 'regional development plans'. There was broad consensus, in response to the Future Worlds consultation, on the need for some standard products and services across GB, whilst taking account of regional difference (e.g. south-west, north-east).

Flexibility comes in three 'flavours': pricing/markets; local/regional; and wholesale. All six DNOs have a DSO transition plan – which tend to split system purchasing and network construction. There is a commitment to 'flexibility first', learning by doing, and embedding practices as business as usual (BAU), with innovation projects no longer in isolation. 207MW of flexibility has been contracted across all DNOs, most of which have been contracted in the past 2-3 years. DNOs are exchanging a lot of information with the ESO.

DNO supply quality problems are 'localised', but a common language is needed across the UK. DNOs all agreed that there are four common constraint management services differentiated by their timing and means of dispatch - Scheduled Constraint Management, Pre-fault Constraint Management, Post-fault Constraint Management, Restoration Support (Open Networks Project DSO Service Requirements). There is currently detailed discussion on 'core products' with explanation of locational difference.

3.2 Market actor perspectives: Evolving value characteristics of flexibility

It was suggested that there is a long way to go before flexibility is BAU for the DNOs. Some participants felt that DNOs need to make progress more quickly, by ramping up the flexibility tenders and lock-in via RIIO2 on competition on load-related capex. DNOs know they need to contract DSF to avoid cost increases and want to bring it up the merit order.

With constraints on national and local systems, and wholesale markets, is it possible to have signals from all three areas to achieve the most efficient outcome? There is a need to re-think market design in ways which integrate these three areas. DSF providers noted how National Grid took 'a punt' on Enhanced Frequency Response (EFR), which in turn stimulated the market, paving the way for FFR. Similar 'bravery' is needed at a local level. Some DNOs have run competitions with caps on prices and procured nothing as a result. Demand side providers need to see that it is possible to have a contract with DNOs and make money.

Data needs to be accessible and free. TfL (Transport for London) is involved in an open data project. Transmission needs to procure bigger units – such as storage, but no one is building >50MW due to planning law and co-location issues, and the clustering of connections is not happening due to restrictions on DNO network. DNOs and the ESO are sharing more information and data than ever before.

Western Power Distribution (WPD) has opened data on 70 substations, and many DNOs use service providers for network services. WPD has a Network Innovation Competition (NIC) project where external parties including community groups have developed apps at substation level. Other DNOs are also making more data available, subject to cyber security. Data on carbon intensity is also made available by the ESO and WPD. ElectraLink is looking at making meter data available. BEIS would like the Data Taskforce to be bold on what data can be put out. Lots of different stakeholders are engaged with the work – including from the energy industry, but also from other sectors (such as telecoms, food etc.). But it is important that the Taskforce finds out from market actors what they need and where the gaps are. National Grid ESO puts out as much data as feasible (subject to commercial constraints) – albeit it is not always easy to find.

'We have to go quicker' to develop new markets: day-ahead auctions 2021; developing the products in SOF; DNOs need to take more risks to develop local/regional markets. Leadership is needed. National Grid ESO is starting with more established markets, IS teams need to deliver more quickly (e.g. the ESO auction platforms). Once the auction is up and running, it might take up to two years of (week ahead, day ahead) trialling EPEX. 6 months of auction data will be needed. Then 12 months after that it will be possible to kick off a well-designed auction for day ahead while keeping week ahead going.

This suggests approximately 4 years until an auction can deliver from first concept. Concern was expressed about a timing disconnect between developing new markets, and then prematurely taking things away, which impact business models in the near-term (e.g. network charges). Steering group members reiterated that DSF opportunities and rewards should not be removed until there is something to replace them with. This, however, leaves a problem in 'signalling' as stakeholders want system change faster than may be practicable. Bringing in new products with IS work-arounds is not ideal e.g. CDCM (Common Distribution Charging Methodology) are doing just that. It is also not appropriate to bring in new products ahead of their requirement. There is a major issue in terms of 'equilibrium'. As each market becomes competitive (STOR, FFR) the prices reduce, and the ESO is asked to come forward with new products to 'fill the missing money' gap.

DSF providers need to see a 'whole pot' of opportunity – plus understand the legacy contracts of what might lock DSF out. The ESO does not need to create new markets simply to deliver new revenue to DSF providers. DSF providers need to understand when future balancing problems may arise for the system – and what problem needs solving by when. In other words, a holistic view of where the opportunities may lie nationally, regionally and locally.

National Grid ESO does not yet know what is needed. Just that there are likely to be potential problems in future, not apparent today. Did the regional voltage RFI give DSF providers the information needed? The volume was too high. Most mature markets (e.g. frequency) are solving national issues. But some system operability issues are becoming more regional. So it is important to understand the interplay between ESO and DNOs.

4. Power Responsive activity update

The Power Responsive Annual Report 2018 will be published in early March. A draft will be circulated to Steering Group members for comment. The spring Flexibility Forum is likely to be replaced by a webinar. The Power Responsive Annual Event will be hosted in June/July 2019 – with a trade 'fair' approach and presentations as in 2018. Max 350 attendees. Need to address issue of delegates registering but not turning up.

The next Steering Group meetings take place on 2 May 2019 and in July (date tbc). Feedback is welcomed on the agenda & discussion topics for 2019-20 – a proposed list will be circulated. It was noted that retail representatives have left the companies – and it would be helpful to identify new steering group members (e.g. in food, production, refrigeration) – MEUC to investigate.

5. AOB and next steps

Joe Ernst-Hermann (Crown Commercial Service) noted that a CCS Smart Energy Framework will go live in September 2019. CCS have already got a charge-point scheme. The EV Energy Task Force reports in September 2019. A new web-based switching service has been developed and recently announced by the Secretary of State.

Attendees

Name	Company	Sector representation
Cathy McClay	National Grid	Chair
David Capper	BEIS	Policy & Regulation
Charles Phillips	BEIS	Policy & Regulation
John Parker	Ofgem	Policy & Regulation
Nathan Macwhinnie	Ofgem	Policy & Regulation
Colm Murphy	National Grid ESO	System Operator
Beth Warnock	National Grid ESO	System Operator
Roger Hey	Western Power Distribution	Distribution Network Operator
Fiona Navesey	Centrica	Large Supplier
Jo Butlin	EnergyBridge	Market Commentator
Robert Buckley	Cornwall Insight	Small Supplier
Francisco Jose Carranza Sierra	Nissan	Electric Vehicles
John Prendergast	RES	Storage
Marek Kubik	Fluence Energy	Storage
Justin Andrews	Elexon	Electricity Market
Yselkla Farmer	BEAMA	Enabling Technologies
Caroline Bragg	ADE	Decentralised Energy
Alastair Martin	Flexitricity	Aggregator
Wayne Muncaster	GridBeyond	Aggregator
Eddie Proffitt	MEUC	I&C (industry)
Joe Ernst-Hermann	Crown Commercial Service	I&C (public sector)
Andy Pennick	United Utilities	I&C (utility)
Richard Eaton	Aggregate Industries	I&C (building & materials)
Judith Ward	Sustainability First	Secretariat
Clare Dudeney	Sustainability First	Secretariat

Apologies:
Haydn Young, Retail Energy Forum
Adam Sims, National Grid
Adrian Sellar, National Grid