Low Carbon Networks Fund
Full Submission Pro-forma

Section 1: Project Summary

1.1 Project title

The GB Flexibility Market

1.2 Funding DNO

Northern Powergrid (Northeast) Limited

1.3 Project Summary

The GB Flexibility Market (GBFM) project will trial commercial arrangements aimed at reducing the cost of flexibility services to distribution network operators (DNOs). These arrangements could reduce costs to DNOs by up to £30m a year.

The project will build on learning about the role of flexibility services that Northern Powergrid's Customer-Led Network Revolution (CLNR) project has achieved. Flexibility services are products such as demand side response (DSR) and electrical energy storage (EES), which provide for changes in demand or generation. They are likely to be of increasing importance to DNOs in a low-carbon economy.

This is an ambitious project, which will develop innovative commercial arrangements to allow DNOs both to provide flexibility and access it from a variety of sources. We believe it to be ambitious because 1) it will trial commercial solutions in a transparent market as an alternative to traditional technical solutions and 2) it brings together the key participants or actors across the electricity value chain. It will investigate options for flexibility to be shared between parties in the supply chain and ways to reduce the transaction costs associated with purchasing DSR, with the aim of lowering the cost to DNOs. The project will include live trials with DNO customers to test the feasibility and the cost-effectiveness of these arrangements, and will produce a detailed plan for their implementation.

1.4 Funding

Second Tier Funding request (£k)	16,379		
DNO extra contribution (k)	9,274	**External Funding (£k)**	4,030

1.5 List of Project Partners, External Funders and Project Supporters

Project Partners:

British Gas, Centrica Energy, National Grid, Elexon, Durham University, EA Technology, Frontier Economics

Project Collaborators:

KiWi Power, ESP, Flexitricity, EnerNOC and Asda

1.6 Timescale

Project Start Date	January 2013	**Project End Date**	December 2016

1.7 Project Manager contact details

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Section 2: Project Description

2.1 Aims and objectives

This section describes the problem that needs to be resolved in order to facilitate the low-carbon future, the Methods being trialled to solve the problem, and the trials being undertaken to test that the Methods work.

Problem which needs to be resolved

Flexibility services, such as DSR and EES, can potentially play a major role in allowing DNOs to efficiently release network capacity to enable the move to a low-carbon economy. However, under bilateral trading, accessing flexibility may not be a cost-effective option for DNOs.

GB DNOs must maintain safety and quality of supply and meet their statutory obligations by efficiently delivering electricity. Load is expected to grow significantly to 2030 and beyond, driven in part by new technologies such as electric vehicles (EVs) and heat pumps. To continue to meet obligations, additional distribution network capacity will be required. Traditionally, capacity has been delivered by providing higher rated assets through capital investment. However, DNOs are increasingly beginning to contract flexibility services to free up capacity. These flexibility services include DSR (incentivising customers to shift electricity demand across time, usually within a day), EES and changes to the output of embedded generation. Each aims to reduce maximum power flows through key distribution network assets.

The provision of DSR and other types of flexibility can play a major role in supporting the low-carbon economy. In particular, deployment of flexibility can:

- reduce costs by helping to defer investment in distribution networks (as well as in transmission networks and generation capacity);
- improve security of supply by reducing the impact of network faults or planned outages on supply; and
- reduce carbon emissions both by releasing distribution network capacity more quickly and thereby increasing the rate at which low-carbon technologies (such as heat pumps and EVs) can be accommodated on distribution networks, and by increasing the scope of the electricity system to absorb renewable generation.

Sustainability First's GB Electricity Demand project, and a range of Low Carbon Networks (LCN) fund projects (including the CLNR project) are demonstrating that there is customer appetite for participating in DSR schemes, and that technologies to enable DSR and storage can be deployed. However, LCN fund projects are also finding that accessing flexibility can be difficult and costly for DNOs. This is because the current industry approach to accessing DSR and other flexibility services is fragmented across the value chain. Specifically, flexibility services are currently contracted bilaterally. This creates a number of barriers for DNOs, including:

- **Limited financial incentives from DNOs.** Flexibility services can create benefits across the value chain. The value to one party will often be lower than the total value across the value chain. However, it is currently difficult for DNOs to share these services with other market participants. A recent report (Pöyry, December 2011, *Assessment of DSR price signals*) suggests that, in a bilaterally-contracted world, GB DNOs are unlikely to be cost-competitive with other users of flexibility and hence risk being `locked-out' of new and existing resources.

- **High transaction costs.** Bilateral contracts can attract significant transaction costs, including information requirements for the providers of flexibility services. This issue was recently highlighted by Ofgem (Ofgem, July 2012, *Promoting smarter energy markets: a work programme*).

- **Low customer awareness of the potential to sell DSR.** A lack of transparency in the market means that customer awareness of the potential to sell DSR is low. Cultural and institutional factors such as lack of awareness were found to be among the most important barriers to the provision of DSR in a recent piece of analysis for Ofgem (Element Energy, July 2012, *Demand side response in the non-domestic sector*).

- **Lack of access across the value chain.** A significant amount of flexibility is unavailable to GB DNOs as it has already been committed to other market participants for specific purposes such as the Short Term Operating Reserve (STOR).

These barriers are likely to grow in importance in the move to a low-carbon economy as the demand for

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flexibility services from DNOs increases. There are three main reasons.

- **The impact of heat and transport electrification.** Heat and transport electrification will, in the absence of flexibility, significantly increase peak demands on distribution networks. Flexibility services can help manage this. At the same time, this type of load may be amenable to DSR and so the amount of demand that is flexible may increase.

- **The impact of intermittent electricity supply from renewables.** The increase in intermittent electricity supply from renewables may change the pattern of demand on the distribution and transmission networks, to the extent that customers can be encouraged to demand more electricity when output from intermittent sources is high. Access to flexibility will allow DNOs and the transmission system operator (TSO) to manage any additional peaks associated with this demand.

- **The impact of an increase in local embedded generation.** Local embedded generation requires networks to cater for greater ranges of power flows than those associated with demand alone. Flexibility services can reduce the impact on network reinforcement requirements.

DNOs are therefore likely to have a greater demand for flexibility services in a low-carbon economy. As well as a greater role for flexibility services in general, there is expected to be a greater role for DSR and storage in particular, as flexibility that involves reductions in peak demand may be the most useful to DNOs. Recent work by the ENA and Energy UK (July 2012, *Smart demand response: a discussion paper*) recognises the importance of overcoming barriers in this area.

Methods being trialled to solve the Problem

Work recently commissioned by DECC (Imperial College and NERA, August 2012, *Understanding the Balancing Challenge*, Redpoint Energy and Element Energy, August 2012, *Electricity System Analysis*) highlights the additional benefits that can be gained from using distribution-connected storage and DSR to provide benefits across the value chain, rather than just to one party. The GBFM project aims to trial commercial arrangements which aim to reduce the costs of flexibility to DNOs by allowing these benefits to be realised. Two Methods will be trialled (Method 1 and Method 2) with a decision point on Method 2 towards the end of the first year of the project.

Method 1 - Network operator trials

Method 1 aims to reduce costs to DNOs by facilitating the sharing of flexibility with the TSO. Figure 2.1 outlines the key participants in this stage. In summary, Method 1 will involve Northern Powergrid and National Grid as the DNO and TSO, jointly procuring flexibility services. Northern Powergrid and National Grid will assess their joint network requirements and present combined propositions to the providers of flexibility. The flexibility providers in Method 1 will be the commercial aggregators, Asda, and Northern Powergrid's storage assets delivered from the CLNR project. The trials will simulate the network requirements but there will be a physical delivery of the flexibility response from the flexibility providers. An innovative trilateral agreement will be created along with operational learning during this phase of the project.

There should be significant potential for DNOs and the TSO to share flexibility resources, as their requirements are very similar in terms of the periods over which flexibility is needed. The main difference is that the TSO requires a national response and DNOs require local responses, generally driven by short-term plant outages. Flexibility is held by both parties as insurance and use rates are very low. Because the DNO requirement for response is locally specific, the DNOs in particular will contract for a lot of flexibility that will stand unused unless an issue arises in a particular location. Our analysis, based on the DNO requiring 10 days of response from 6% of customers during the winter season, suggests that DNOs are likely to be using less than 1% of the potential availability on their networks at any one point in time; the remaining 99% would therefore be available for the TSO to use. This illustrates that there is significant potential for the same contracted flexibility resource to be shared between the DNO and TSO, reducing the costs that DNO customers bear.

Method 2 - Multi-party trials

Method 2 aims to further reduce costs by allowing DNOs to share flexibility with the TSO and other parties, such as suppliers/energy traders, and by reducing transaction costs by establishing a market platform. The market platform is a screen-based system which will enable purchasers of flexibility to present their requirements and potential providers of flexibility to offer their services via the market platform. The market platform may operate a reverse auction to match purchasers and providers. It will allow aggregation of the

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requirements of purchasers and the needs of providers, and it will identify opportunities for sharing of availability between purchasers. This sharing should mean that DNO customers bear less of the fixed costs of securing availability. Transaction costs will also be reduced as the platform will match providers and purchasers, and bilateral contract negotiation will not be required. Reduced transaction costs may also attract more providers of flexibility to the market.

Figure 2.2 outlines the key participants in Method 2. If the project partners agree to proceed with the multi-party trials, Method 2 will involve Northern Powergrid, National Grid and Centrica Energy, as the TSO, DNO and supplier/trader respectively, procuring flexibility services from the providers of flexibility. A series of workshops will capture the procuring parties' flexibility requirements to create products that can be offered to the market via the market platform.

The providers of flexibility in Method 2 will be the commercial aggregators, aggregated British Gas customers, Asda and Northern Powergrid's storage assets. British Gas will use the experience developed during the CLNR project to target customers and technologies that provide the most cost-effective means of delivering DSR, including those with smart appliances, heat pumps and night storage heating.

A GBFM Operator will act in a similar way to a power exchange operator, matching buy orders against sell orders, sending dispatch instructions, undertaking settlement and reconciliation and potentially acting as counter-party to both buyers and sellers. Elexon will take on this role during the trial. The procurement, sales, matching, dispatch and settlement processes will be undertaken via the market platform providing transparency to all participants as opposed to bilateral or trilateral arrangements. The market platform is a key deliverable for the project and if the trials are successful will provide a prototype for a national system. The trials will again simulate the TSO, DNO and supplier requirements but there will be a physical delivery of the flexibility response from the flexibility providers.

The project will capture the requirements and capabilities of all the market participants and other stakeholders during the assessment phase of the project and the requirements and capabilities will be tested during the trials. However, value-add opportunities to build on the assessment and design process may present themselves as the project and trials progress. Specifically, we may find that providers of flexibility offer services that we had not forecast or explicitly sought. For this or similar circumstances the project will have the flexibility to ensure these items can be built into the work programme.

Trials being undertaken to test that the Methods work

Each Method will be trialled separately. Provided that the work carried out in Method 1 continues to demonstrate the incremental benefits forecast for Method 2, two trials will therefore be carried out. Both trials will be undertaken in the Northern Powergrid distribution network area, drawing as much as possible on existing technology and customer groups involved in the current CLNR project.

Desktop research

Before undertaking the trials, a significant piece of desktop research will be carried out. The aims of the research will be to:
- capture learning from previous work in this area, including from previous LCN fund trials and international experience (an initial review of international experience is included in Appendix 10);
- understand the requirements from participants in both Methods and other stakeholders;
- undertake a modelling exercise to determine the most important scenarios to trial and to provide an initial evaluation of the costs and benefits of both Methods; and
- feed the requirements into the detailed design of sharing arrangements for Method 1 and the detailed design of the market for Method 2.

Stakeholder engagement

Stakeholder engagement is a very important part of the project. Industry involvement will be wide and will include contributions from groups such as the following:

- Potential market participants:
  - networks (DNOs, TSO);
  - suppliers, generators and energy traders; and
  - aggregators and large customers.

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•Other core stakeholders:
- government and regulatory bodies;
- academic institutions;
- consultants;
- technology vendors;
- related associations and organisations e.g. consumer representatives; and
- market operators.

It is important that we involve the right stakeholders, and that we keep them engaged throughout the process. We think there are three ways to ensure this involvement:

•We will set out a clear process with set milestones, actions and outputs.
•We will arrange working groups or seminars to facilitate input. We will investigate the option to use existing working groups reviewing demand response. For example a new Smart Grid Forum working group, run by Northern Powergrid could be set up. Alternatively, we could set up new working groups based on the format of Elexon Issues or Change Committees.
•We will work closely with industry bodies such as Energy UK and the ENA to ensure we engage across the sector.

Our plan is to engage and communicate with stakeholders, for example in the following in five ways:

• a PR campaign (e.g. via industry media, social media such as project partners' twitter accounts and networking events) to raise awareness of the project's brand;
• road-shows, working groups and seminars to capture input at the design stages of the GBFM;
• consultation processes;
• trial observation opportunities; and
• contribution to the knowledge capture and dissemination work stream.

Further detail on this methodology is given in Section 5.

In addition, new social research will aim to understand more about the institutional barriers (e.g. regulation, policy, organisational cultures) to new commercial arrangements to determine how these might be overcome. This will involve a series of interviews or focus groups with parties from the sector.

Trials

Method 1 will be trialled via simulation and physical tests of resources designed to represent conditions in the near term, 2020 and 2030. A physical trial will take place in winter 2013/14 and summer 2014. The trial will involve real participation from the providers of flexibility (storage, aggregators and large I&C customers). Events which require the purchase of flexibility by the DNO and TSO will be simulated. Simulating demand for flexibility will allow testing of a range of scenarios, including ones which represent potential network conditions in a low-carbon economy, specifically in 2020 and 2030. Following desktop research and market modelling, a decision will be made on whether the potential incremental benefits from a multi-party GBFM continue to warrant it being trialled. Assuming a decision is made to proceed, Method 2 will be trialled in winter 2014/15, summer 2015 and winter 2015/16. A market platform will be developed which allows multiple participants to submit their detailed requirements and offers to the market. The platform will match providers and purchasers, aggregating the requirements and offers from different parties, and allowing sharing where this is beneficial. This trial will again involve real participation from the providers of flexibility and simulated events which stimulate demand for flexibility from purchasers.

Learning outcomes

Together, the desktop research, the stakeholder engagement and trials will aim to address the following six Learning Outcomes, in the context of near term electricity sector conditions and likely electricity sector conditions in 2020 and 2030.

Learning Outcome 1. How can DSR provide flexibility to DNOs?
• What are the characteristics of this flexibility, including in terms of its location?
• What are the associated costs?
• How much confidence can DNOs attach to this flexibility?

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Learning Outcome 2. How can storage supply flexibility to DNOs?
- What are the physical characteristics of the supply of flexibility from EES?
- What are the costs?
- How can DNOs trade and share the value of the storage?
- How much confidence can DNOs attach to this flexibility?
- What regulatory and commercial changes are required for the participation of storage?

Learning Outcome 3. What technological changes are required for the DNO to access this flexibility?
- What technology is required to dispatch and operate EES and DSR optimally?
- How can these technologies be integrated into existing systems?

Learning Outcome 4. How should the network operator sharing arrangements be implemented?
- How much additional capacity could these arrangements release?
- Would they release it cost-effectively?
- What are the direct carbon impacts?
- What are the impacts on security of supply?
- How can legal, economic, commercial, social and technical barriers be overcome?

Learning Outcome 5. How should the multi-party GBFM be implemented?
- How much additional capacity could the multi-party GBFM release?
- Will it release this capacity cost-effectively?
- Would the GBFM reduce the risk of third parties triggering distribution network constraints, e.g. if suppliers contract for demand increases when the output of intermittent renewable electricity generation is high?
- What are the impacts on security of supply?
- What are the direct carbon impacts?
- How can legal, economic, commercial, social and technical barriers be overcome?

Learning Outcome 6. What does each new form of commercial arrangement mean for DNO business operations and engineering policies?
- What consequential amendments to GB and European codes and regulations arise, for example a review of the demand control provisions of DCUSA?
- Do network planning standards and internal policies need to change?
- What new network planning tools are required?
- How can the learning be applied to all DNOs?

These Learning Outcomes are mapped onto the SDRCs and outputs of the project in Figure 2.3.

The trials will benefit from the use of technologies from the CLNR project, including up to 2.85 MVA of storage and a power flow management platform which facilitates the despatch of storage and DSR resources for Northern Powergrid. The project will aim to access customers from the CLNR project trials, including around 100 customers who already have controllable heat pumps or smart appliances. The project will also build upon the significant amount of detailed learning on the most effective ways to deliver DSR being produced by the CLNR project. This will be particularly useful in the non-domestic sector as there is currently limited information on how that sector uses energy. There may be the potential to increase the benefits of the project by collaborating with UK Power Networks on their Tier 2 project bid Smarter Network Storage. Further details are presented in Appendix 11.

The solutions which will be enabled

The two Methods being trialled will reduce the cost of DSR and other flexibility services to DNOs by enabling sharing and, in the case of Method 2, by reducing transaction costs. The solutions being enabled therefore will release network capacity more efficiently than in the Base Case. Ultimately this cost reduction should result in a reduction of overall electricity sector costs and costs to DNO customers. By establishing a transparent and efficient market, Method 2 should also have the following benefits:

- **Greater visibility of incentives.** A more transparent market and stronger financial signals should help increase awareness of the financial incentives among the providers of DSR. This should increase the number of customers who offer flexibility resources.

- **Efficient access.** A transparent and liquid market should allow those parties with the highest value for flexibility services to access these services, and should bring forward services with the characteristics that are most valuable.

2: Project Description cont.

2.2 Technical description of Project

This section provides a technical overview of the Methods being deployed and an outline of why they are innovative. Both Methods in the GBFM aim to help DNOs access flexibility products through the trialling of innovative commercial arrangements. In Method 1, products will be shared with the TSO through a system of trilateral trading. In Method 2, a platform will be developed which allows trading and sharing of flexibility products between multiple parties.

Technology trading and sharing

Two flexibility product types will be included in both Methods:

- dispatch, i.e. a firm commitment to deliver an increase or decrease in MW at a given location and at a given time; and
- availability, i.e. an option to buy physical flexibility at any point within defined future time windows.

For Method 1, contracts for these products will be negotiated by the DNO and TSO with individual I&C customers and aggregators. A set of trilateral commercial and operating frameworks will be developed which allow sharing of flexibility between DNOs and the TSO. These frameworks will specify procedures which allow the costs of flexibility to be shared, and which can be both used in the trials and developed further for more widespread roll out.

For Method 2, a market platform will be provided. This will be designed to allow providers and purchasers to trade dispatch and availability products; potentially through a continuous reverse auction process. The products will be standardised around a set of parameters, so that the details of what each purchaser needs and each provider can supply will vary. For example, purchasers and providers can specify the location of the flexibility. This will be a key parameter, as it is required for the DNO to assess the ability of the flexibility to contribute to the capacity of the network. The structure of the generic availability product and the generic dispatch product (including all the rules about payment terms, delivery and verification, credit requirements and so on) will be fixed, but key technical parameters (e.g. MW levels, time windows in which delivery is required) will not be specified, and will be left for market participants to specify. Suppliers and energy traders will join the trial alongside the other participants for Method 2.

In particular, it is envisaged that the platform could allow:

- purchasers of flexibility to set product parameters such as kWhs, response times, location and duration;
- providers of flexibility to respond to purchaser parameters, or to unilaterally post their ability to provide flexibility;
- matching of the requirements of purchasers and providers in a way that facilitates sharing;
- delivery of instructions for dispatching to the providers and confirmation to the purchaser;
- metering and data collection to register the amount of energy dispatched; and
- settlement and reconciliation of data and accounts.

Under certain circumstances, the use of flexibility by one party may impose costs on another party. For example, if a supplier dispatches an increase in demand during a period of high wind generation, the cost to the DNO of accommodating this could be very high. Method 2 will trial the use of price signals to deal with these conflicts.

Technology requirements

Investment in new technologies will be required to deliver each Method. At this stage we have specified a range of technologies for this purpose. However, the exact technology solutions may vary, as during the project, we will procure those technologies which most cost-effectively meet our needs.

To trial Method 1, the DNO requires network monitoring equipment to observe effects, a power flow management system with control loops, which allows a call for DSR or other flexibility services to be generated when thermal or voltage limits are being approached, and EES installed at distribution network level. The central power flow management system and EES are being installed in Northern Powergrid networks as part of the CLNR project trial, so funding to establish them is not required as part of the GBFM. There will be a requirement for additional network monitoring at the chosen substations and at a night storage testing area, and to modify the power flow management system and its interfaces to support the trials. Technology is already in place to allow supply of flexibility from large customers and through aggregators, as these parties already sell flexibility through bilateral contracts. Some modification to interfaces may be required to better facilitate these trials.

2: Project Description cont.

All of the technologies required in Method 1 will be also required in Method 2. In addition, to trial Method 2, a new type of market platform will be required. This platform sits either side of the technologies described above to facilitate the striking of contracts for flexibility, which can then be called using the technologies described above and to settle any payments due after flexibility has been called. We have completed a request for information (RFI) process for the design of a platform which allows purchasers and providers to trade availability and flexibility through a reverse auction process. Further details on the market platform are set out in Appendix 6. An interface from the Northern Powergrid DSR control system to the GBFM will be required. Developing a process to identify network constraints on the use of DSR by other participants is outside the scope of this project. As we intend to use price signals to manage constraints within this project, we shall use the output from the ongoing development of the EHV Distribution Charging Mechanism (EDCM).

For Method 2, a set of technologies are also required to ensure that flexibility can be supplied from domestic and non-domestic customers. These are:

- smart meters for domestic and non-domestic customers to establish a baseline and verify any flexibility services provided;
- a load-control device for night storage customers;
- interconnectivity with existing building management head-end systems and communications to deliver services from commercial and institutional buildings to smart meters;
- technologies such as heat pumps, storage and smart appliances which increase the scope for flexibility among domestic and non-domestic customers; and
- a platform which allows British Gas to aggregate DSR from smaller customers, and respond to calls from purchasers of flexibility, or from the GBFM platform.

Many of the smart meters and low-carbon technologies are already being put in place for the CLNR project trial. British Gas are also developing an aggregation platform allowing for a variety of customer and technology types to be trialled, which can be used by the project.

Technology requirements for simulation

Technologies will also be required to facilitate the simulation of the impacts of 2020 and 2030 scenarios on networks and to extrapolate and scale up the results of the experimental trials. There are two elements to this simulation:

- First, a technical and economic model will be developed before the trials to inform their design. This model will help determine the scenarios which should be trialled. It will also be used to evaluate the GBFM prior to the trial to inform the decision point. Further detail on this modelling is provided in Appendix 8.

- Second, the Smart Grids Simulation and Emulation Laboratory at Durham University (which is also being used in the CLNR project) will be used to simulate network power flows. The laboratory allows for small scale real equipment to be used and interfaced in real time with a large scale model of the power system. It includes the capability of emulating small scale storage and flexible demand and generation. The distinctive feature of this laboratory is the ability to have real time power and control interactions between the physical emulation and simulated parts of this system. This functionality will play a central role in extending the trials and adding value to the results of the project. As this laboratory already exists, this work will not require the purchase of significant additional equipment.

Outline of why the Project is innovative

A number of trials of DNO-led flexibility are being carried out, for example in current LCN fund projects such as the CLNR and Capacity to Customers. However, no projects have yet looked at commercial arrangements which explicitly aim to reduce the costs of this resource to DNOs. The development of systems to share and trade flexibility is the major innovation of this ambitious project. We have conducted an international review of markets for flexibility services which allow the participation of DSR. We have not found any market that includes a focus on meeting the needs of the DNO (e.g. by including locational parameters in the needs of the market) and which explicitly aims to facilitate sharing of flexibility services between market participants.

2: Project Description cont.

In particular, innovations in this project include:

- inclusion of the locational factor in trading;
- trialling of the use of price signals to limit the use of resources by other parties where this would have an unacceptably negative impact;
- the development of trilateral arrangements for network operator procurement of flexibility;
- the design and deployment of a multi-party flexibility trading system; and
- the development of a prototype platform for the trading of this flexibility.

2.3 Description of design of trials

The trials aim to test the Methods under a range of conditions. A process of Experimental Design has been undertaken with the aim of ensuring that the trials generate statistically significant results while being no larger or more complex than necessary. The trial design and likely margins of error have been assessed following advice from Durham University. Durham University will lead on statistical analysis and methodology for the project. This process has aimed to ensure that the trial is expected to produce robust results as cost-effectively as possible. Further detail on the trial design is given in Appendix 7.

The trials will produce a set of outputs (e.g. network capacity released through flexibility) which must be interpreted in terms of the statistical confidence that can be attributed to them, and their applicability outside the geographic area of the trial. We have identified the set of factors which will affect the trial outputs and which vary across GB. These include, for example, network and load-types. There is a need to ensure that the trial covers a range for each factor that is large enough to deliver robust results. Where there is a need to extrapolate results across GB, we have identified estimated confidence intervals associated with the extrapolated values. Specifically, we designed the trial to include sufficient calls from resources that should allow us to extrapolate results across GB with confidence-intervals that we expect to be better than 30% of their mean values.

To address the questions in Learning Outcomes 1 and 2 on the physical characteristics of flexibility, and in particular on the confidence that can be attributed to it, a real supply of flexibility from DSR and storage will be incorporated into the trial. Events which require the DNO, TSO and suppliers to access flexibility will be simulated. This is to ensure that enough events where flexibility is required occur during the trial; that 2020 and 2030 conditions can be represented and that subsequent calculations of reliability will have reasonable confidence intervals. Employing simulation in this way will help minimise the costs of the trial, without unduly affecting the robustness of the results.

The substations in this trial will be selected according to the range of factors which may affect the results, such as the need for extra capacity, coverage of categories such as load and network-types and potential for flexibility resources. During the trial a pool of 20 substations will be monitored (five delivered by the CLNR project with 15 new sites delivered by the GBFM project). Flexibility will be purchased for 10 of these. The remainder will be used to increase coverage of factors such as network and feeder types that affect the types and number of flexibility resources that could in theory be connected to them. Flexibility resources will be virtually connected to substations if they cannot be physically connected to the relevant substations.

2.4 Changes since initial screening process

The second tier funding request has decreased from £17.0m to £16.4m. The subsequent budget process has involved all the project partners agreeing roles, responsibilities and accountabilities which have then been translated into resourcing and costing requirements. In addition, the costs associated with the trading platform have been refined following the RFI process.

The project partners are unchanged from the initial screening phase. The initial screening submission noted the requirement for involvement by the aggregators, a large I&C customer and technology providers. KiWi Power, Flexitricity and Energy Services Partnership have already signed a Memorandum of Understanding and we are in discussions with other aggregators. Asda will represent the large I&C energy user. The technology providers will continue to participate in the project as suppliers.

2: Project Description Images, Charts and tables.

Figure 2.1 Method 1 – Network operator trial

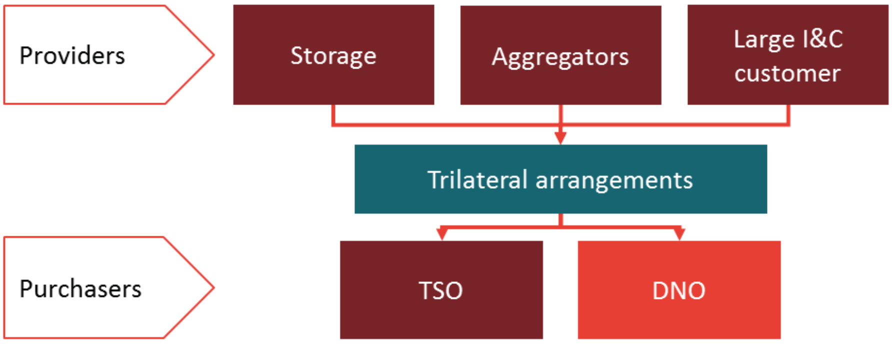


Figure 2.2 Method 2 – Multi-party trials

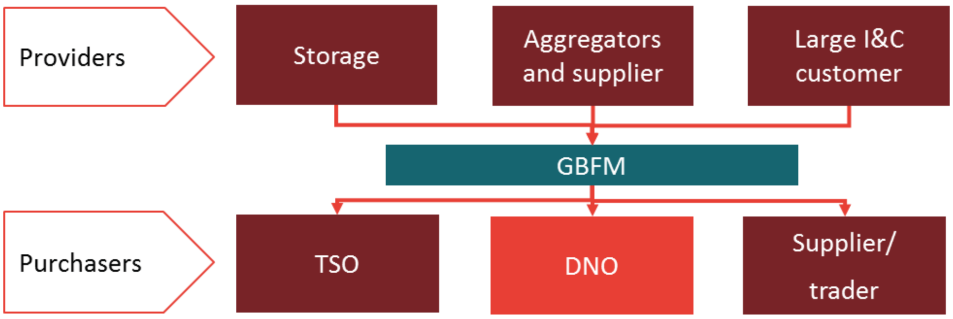


Figure 2.3 Learning outcomes, SDRC and final outputs

Learning Outcomes	SDRC Criteria	Final Outputs
How can DSR provide flexibility to DNOs?	Produce robust recommendations on measures required for DNOs to make use of demand side response (DSR) based on robust trialling of the Methods.	Report setting out the contribution DSR can make to DNOs.
How can storage supply flexibility to DNOs?	Produce recommendations on measures required for DNOs to trade and share DNO-storage based on robust trialling of the Methods.	Report on contribution of storage to DNOs and recommendations on measures required to allow DNOs to trade and share storage published.
What technological changes are required for the DNO to access this flexibility?	Ensure technology is in place to allow the project to access flexibility which will demonstrate robust and applicable trialling of each Method.	Additional monitoring equipment in place.
How should the network operator-TSO sharing arrangements be implemented?	Design and undertake robust network operator (DNO-TSO) trial, analyse the results and produce recommendations.	A set of commercial and operating frameworks for DNO-TSO sharing of flexibility.
How should the multi-party GBFM be implemented?	Design and undertake robust multi-party trial, analyse the results and produce recommendations.	A set of detailed market rules for a multi-party flexibility market, and delivery of a prototype market trading platform.
What does each new form of commercial arrangement mean for DNO business operations and engineering policies?	Produce recommendations and roadmaps which set out how the Methods could best be applied to all DNOs, and communicate this learning.	Engineering guidelines and codes of practice for use of flexibility by the DNO.

Section 3: Project Business Case

The GBFM project aims to facilitate lower cost access to DSR and other flexibility services for DNOs. It has the potential to reduce costs for DNO customers by allowing reinforcement to be deferred. We estimate the net benefits of Method 1 as £255.6m and Method 2 as £866.9m at GB scale to 2040. In line with guidance from Ofgem, these figures have not been discounted.

This section presents a business case justifying the merits of undertaking the project and setting out how the project links to changes Northern Powergrid would like to make to its business over the next 5-10 years.

3.1 Benefits of the GBFM to DNOs

The GBFM project will evaluate the net benefits to DNOs of two systems to share and trade flexibility services in the move to a low-carbon economy. For the purposes of this bid, we have carried out initial analysis of the costs and benefits.

This analysis is based on the roll out of low-carbon technologies required to meet the Government's Carbon Plan. It suggests that there is the potential for significant financial benefits from both Method 1 (a system of sharing flexibility between the DNO and TSO) and Method 2 (a multi-party GBFM market).

These benefits are driven by the potential of both Methods to reduce the costs of flexibility to DNOs. Our analysis suggests that once flexibility can be shared with other users (e.g. the TSO), the cost to the DNO of the flexibility will fall below the cost of reinforcing networks. The expected reduction in transaction costs that may be associated with Method 2 may further reduce costs.

We have not quantified all of the benefits to DNOs from these Methods. In particular, there are likely to be additional benefits associated with the option value from using flexibility. Flexibility can be purchased quickly when required. Under conditions of uncertainty over the growth rate of demand in different localities, this may help to reduce the risk of stranded assets.

We estimate the financial benefits of each Method to be trialled in the GBFM in three steps.

- We first identify a cost per kW of capacity in the Base Case - that is, the most efficient way to release network capacity currently in use on the GB distribution network. Further details on this step are presented in Appendix 5.
- We then compare the Base Case costs with the costs of each Method per kW of capacity released.
- Finally, we scale these estimates up to project and GB level.

All benefits at project scale are estimated between 2017 (the earliest possible year of project implementation) and 2040. GB level benefits are estimated assuming that GB-wide roll out has occurred by 2019, based on the assumption that the Methods would take two years to roll out across the country (see Section 5). We summarise the assumptions made in the analysis in Table 3.1.

Base Case costs

To identify the Base Case, we considered two options for releasing network capacity currently available to DNOs: network reinforcement or bilateral contracting for flexibility services. As detailed in Appendix 5, the most efficient of these two options is currently expected to be network reinforcement. As set out in Table 3.1 (and explained further in Appendix 5), we use a figure for network reinforcement based on the ongoing development of the EHV Distribution Charging Mechanism (EDCM).

Method costs

To establish the benefits to DNO customers of the GBFM, we compare Base Case costs to Method costs.

Comparison of the costs of Method 1 to the Base Case

Method 1 facilitates sharing of flexibility between the DNO and TSO. This will allow the DNO to access flexibility services at a lower cost.

3: Project Business Case contd.

We calculate the cost of flexibility to the DNO using a National Grid figure for the average cost of STOR presented in Table 3.1. We then add an estimate of the transaction costs associated with bilateral purchasing of flexibility. These consist of legal costs, commercial resources and engineering input required to set up flexibility contracts and commercial and administration costs associated with settlement. Although additional transaction costs of bilateral trading might be expected from higher levels of disputes and misunderstanding compared to trading in a market, we did not have an estimate for these costs, so they were not included in the quantitative analysis.

To estimate the costs of Method 1, we first estimate the potential for sharing between the DNO and TSO. Given the overlap between the times that the TSO and Northern Powergrid require flexibility to be available, we assume that Northern Powergrid's entire flexibility requirement overlaps with the window where National Grid requires STOR flexibility to be available. In addition, the total quantity of flexibility required by the TSO is likely to exceed the quantity required by DNOs, and the potential to reduce costs through sharing with DNOs may increase the proportion of flexibility the TSO purchases from distribution-connected sources. We therefore assume that the DNO can potentially share all of its flexibility needs with the TSO. We scale the costs up to account for the increased likelihood that a resource will be called on with more than one user, as detailed in Table 3.1.

We also assume that a lower level of confidence (67%) is attributed to the release of network capacity from flexibility than is attributed to network reinforcement. We scale up the price of flexibility to reflect this uncertainty, so that the estimated cost of flexibility per unit corresponds to a unit of capacity released.

Where flexibility is shared, we assume that the cost of the availability is only incurred once. We assume that under sharing, the DNO covers 20% of the cost of the flexibility and National Grid cover the remaining 80%. This split has been assumed given the lack of evidence on how purchasers may split the costs of flexibility between them. The assumption has been informed by the cost increases due to sharing.

Under these assumptions, Method 1 compared to the Base Case entails a cost saving to the DNO of £12/kW in the near term rising to £21/kW in 2040. As mentioned above, on top of this financial benefit, the fact that the Methods allow capacity to be released more quickly means that they may deliver significant option value to the DNOs, for example by allowing DNOs to respond to a higher than expected level of penetration of low-carbon technologies in a given area. We have not quantified this option value in this analysis.

Comparison of the costs of Method 2 to the Base Case

Method 2 involves a multi-party market for flexibility. This differs from Method 1 in three ways:

- transaction costs will be lower due to the market platform, which will match the needs of providers and purchasers of flexibility, avoiding the need for negotiation of bilateral contracts;
- there are more parties in the market with which the DNO can share flexibility; and
- the additional cost of the market platform will be incurred.

As in Method 1, we assume the DNO can share all of its flexibility needs with the TSO. We now also assume that flexibility can be shared between the DNO, TSO and suppliers/energy traders. We assume that the DNO can share half of the flexibility it buys with both the TSO and suppliers/energy traders. We assume that suppliers/energy traders will use flexibility to avoid imbalance charges. In the absence of evidence on the frequency at which they will use it, we assume the additional use increases the overall cost of the flexibility by the same increase as that driven by network operator sharing. We assume that the TSO-DNO-supplier/energy trader cost split is 70%:15%:15%. We continue to assume that a lower level of certainty is attributed to flexibility compared to network reinforcement.

To take account of the fact that the market platform will match the needs of providers and purchasers of flexibility, we assume Method 2 delivers a reduction in transaction costs. We assume that the transaction costs fall for both purchasers and providers in the market. Assuming competitive market conditions, the providers of flexibility pass their transaction cost saving through to purchasers in the market price.

Under these assumptions, Method 2 entails a cost saving to the DNO over the costs of Base Case of £27/kW now, increasing to £36/kW in 2040. The assumptions underlying this estimation are set out in Table 3.1.

3: Project Business Case contd.

Scaling up to Project and GB level

At project level, the Methods will be applied to 20 primaries. As set out in Section 4, our analysis suggests that 2-3MW of capacity can be released on each primary. To calculate net benefits we use the mid-point of this range. Applying these figures gives a project scale benefit of £20.1m for Method 1 and £34.0m for Method 2. These net benefits account for the one-off cost of setting up the market platform.

As explained in Section 4, we have used the Smart Grid Forum's Workstream 3 model to show that the Methods could free up nearly 1GW of capacity by 2030. Specifically, the Workstream 3 model determines when assets will exceed headroom and judges which of a range of mitigations (including reinforcement, demand-side and storage) is best to deploy. The model only chooses flexibility as an intervention when it is cost-competitive with other options for releasing capacity. The driver for interventions is the future change in power flow, and the Workstream 3 model calculates these based on information from DECC scenarios on low-carbon technologies as informed by the work of GL Nobel Denton and Element Energy (EA Technology et al, July 2012, *Assessing the Impact of Low Carbon Technologies on Great Britain's Power Distribution Networks*).

Applying these figures, the total benefits to DNOs at GB scale are £221.7m for Method 1 and £397.4m for Method 2 to 2040. Again, in line with guidance from Ofgem, these figures have not been discounted. They include the one-off cost of setting up the multi-party platform, which we assume rises when the project is replicated at GB scales.

3.2 Benefits to other parties

Method 1 and Method 2 entail benefits for the TSO and Method 2 entails benefits for both the TSO and suppliers/energy traders. These benefits will be shared with customers through a reduction in electricity costs.

TSO

The Base Case assumption is that the TSO contracts bilaterally for flexibility. Our analysis looks only at the flexibility that the TSO shares with the DNO, based on the conservative assumption that the rest of the TSO's requirement for flexibility is procured outside the GBFM (and therefore is not associated with any financial benefits in this analysis). Under Method 1, given its larger demand for flexibility services, the TSO can share the DNO's entire flexibility requirement with the DNO. Additional sharing opportunities with the supplier from Method 2 further reduce the TSO's costs of flexibility. This results in a saving of £2/kW under Method 1 and £8/kW under Method 2 for the TSO. When scaled up to the GB level, this implies that, compared to the TSO's current system of procuring flexibility bilaterally, the TSO (and electricity customers) could save £33.8m under Method 1 between now and 2040. This cost saving increases to £138.7m under Method 2.

Suppliers and energy traders

Suppliers/energy traders can benefit from the GBFM by purchasing flexibility which allows them to avoid imbalance charges. In the Base Case and Methods, we assume that suppliers/energy traders can access flexibility at the STOR price (as set out in Table 3.1). The sharing assumptions set out above result in a cost saving of £330.8m to suppliers/energy traders under Method 2. These savings will be delivered under Method 2 only, as suppliers/energy traders do not participate as purchasers in Method 1.

Total benefits at GB level

Including the benefits to other parties results in a total net benefit of Method 1 at GB scale of £255.6m and a total net benefit of Method 2 of £866.9m.

3: Project Business Case contd.

3.3 Carbon savings

As well as saving costs, both Methods will help save carbon emissions by facilitating the roll out of low-carbon technologies and intermittent generation and through a direct impact on emissions from balancing and losses. The impact on carbon emissions is detailed in Section 4. In line with the comments from the Expert Panel in their 2011 report, we have not quantified total carbon savings. However, we could undertake this quantification if it would be helpful.

3.4 Costs

We have developed a robust set of cost estimates for the delivery of this project.

Costs for the multi-party market platform have been informed by an RFI issued by Elexon. All other costs have been based on estimates provided to Northern Powergrid by partners. These draw heavily on the experience gained in the CLNR project. The total project initial net funding required is estimated to be £18.8m, the outstanding funding required is estimated to be £16.9m (as detailed below), leaving the second tier funding request at £16.4m. External funding of £13.3m would also be provided.

Costs and external contributions are detailed below.

Labour costs:

- Northern Powergrid project management: £1.6m

Equipment

- Network technology (network monitoring and installation costs): £0.8m
- I&C DSR technology (e.g. smart meters):£0.2m
- British Gas customer DSR technology (e.g. heat pumps, smart appliances, batteries etc): £1.0m

Contractors

- Elexon: £1.2m
- National Grid: £0.0m
- Frontier Economics: £1.5m
- EA Technology: £1.3m
- British Gas / Centrica Energy: £1.6m
- Durham University - engineering / statistics: £0.7m
- Durham University / B2B market research - social sciences: £0.2m
- Learning & dissemination: £0.4m
- Legal resources: £0.2m

3: Project Business Case contd.

IT

- IT (Network control system interfaces): £0.5m
- British Gas DSR technology (e.g. connectivity): £0.7m

Other

- IPR (legal costs): £0.2m
- Travel and expenses: £0.1m
- Payments to users (trials and customer engagement): £1.6m
- Contingency: £2.7m
- Decommissioning: £0.2m
- Other: £0.2m
- **Total: £16.9m**

External Funding

DNO extra contribution

- Electrical Energy Storage: £5.4m
- Network control systems: £2.9m
- Network monitoring: £1.0m

British Gas

- Customer DSR equipment (e.g. heat pumps, smart appliances & smart meters): £1.5m
- IT (e.g. DSR communication systems): £1.4m
- Other (e.g. customer engagement): £0.1m

Other

- Commercial aggregators: £0.2m
- Frontier Economics: £0.3m
- EA Technology: £0.3m
- National Grid: £0.2m
- **Total: £13.3m**

The industry partners e.g. British Gas, Centrica Energy, National Grid and Elexon have included their time at cost and in some activities at zero cost for the GBFM project. The consulting organisations, EA Technology and Frontier Economics have utilised competitive market rates for the GBFM project, with both providing a discount relative to standard rates. The industry partners may receive an ongoing business benefit from this project, but for EA Technology and Frontier Economics this is their normal business operations and the agreed rates equate to their opportunity costs.

3: Project Business Case contd.

Contribution to business planning

This project will make an important contribution to changes to Northern Powergrid's business in the next 5-10 years. It will specifically investigate a number of questions around the integration of flexibility into DNOs' business planning. This project will also develop prototypes for the tools required to embed this learning into business processes.

If the GBFM proves successful, Northern Powergrid would factor the flexibility that could be accessed through this market into business plans. For every kW of flexibility that can be accessed through the GBFM, some network reinforcement could be deferred. One of the aims of the project is to understand the confidence we place in flexibility, to understand the relationship between contracted and credited flexibility: for example, for multiple conventional generation sets, 3kW of connected generation defers 2kW of network reinforcement. To the extent that the GBFM allows Northern Powergrid and other DNOs to access more flexibility at lower cost, the DNO can reduce the costs in future business plan submissions.

If the trials show that the Methods can deliver cost savings, a key part of this project will be to deliver a plan for their implementation and roll out. Once either Method has been implemented and rolled out, Northern Powergrid would factor the flexibility that could be accessed through this market into business plans. This would allow reinforcement to be deferred and would deliver cost savings to Northern Powergrid customers.

3: Project Business Case images, charts and tables.

Table 3.1 Assumptions made in the business case

Driver of capacity cost	Assumption	Basis
Avoided cost of distribution network reinforcement	£35/kW/year in 2012	Northern Powergrid's methodology, based on EDCM
	Reinforcement cost rises at 1% a year	Assumption used in the Smart Grid Forum's Workstream 2
Cost of flexibility	£35/kW/year in 2012	National Grid's estimate of the cost of STOR
	Constant over time	Assumption, given uncertainty over the future cost of flexibility
Capacity released per unit of flexibility	67% confidence in flexibility	Based on confidence attributed to steam plant in P2/6
Degree of sharing between participants	Method 1: 100% of flexibility bought by DNOs is shared with the TSO Method 2: As in Method 1 with an additional 50% shared between DNOs, TSO and suppliers	Based on coincidence of requirements for delivery of flexibility between TSO and DNO, and an assumed overlap with suppliers
Use rate for flexibility	TSO: 1-2%	Based on current STOR use rates
	DNO: 0.7%	Based on assumption that 6% of customers are called on to provide four hours of response for 10 working days during a winter season
Impact of sharing flexibility on costs	DNO-TSO: 18%	Based on increase in use rates and the proportion of STOR revenue currently based around use rather than availability
	DNO-TSO-supplier: 36%	Assumption that the cost increase when the supplier shares is the same increase as when sharing with the DNO
How the cost of shared flexibility is split between purchasers	DNO-TSO sharing: 20% DNOs, 80% TSO DNO-TSO-supplier sharing: 15% DNOs, 70% TSO, 15% suppliers	Assumption, informed by the increase in costs due to sharing
Transaction costs	Base case and Method 1: £8/kW	Based on seven man days required to set up a 0.5 MW annual contract
	Reduction with Method 2: 90%	Assumption, based on the fact that the market platform will match the needs of purchasers and providers
MW of distribution network capacity released from flexibility	Method 1: 42MW in 2020, rising to 925MW by 2030, decreasing thereafter Method 2: 48MW in 2020, rising to 944MW by 2030, decreasing thereafter	Based on modelling using the Smart Grid Forum's Workstream 3 model

Section 4: Evaluation Criteria

(a) Accelerates the development of a low-carbon energy sector & has the potential to deliver net financial benefits to future and/or existing customers

This section describes the contribution of the project to the Carbon Plan, the financial benefits and the network capacity released.

Contribution to the Carbon Plan

Solution 1 of the project is delivered by a system for sharing flexibility between the DNO and the TSO. Solution 2 is delivered by a multi-party market for flexibility. Both Solutions will release distribution network capacity more quickly and more cost-effectively than reinforcement. By doing this, they will contribute to the Carbon Plan in three ways:

- by facilitating the roll out of low-carbon technologies such as electric vehicles (EVs), heat pumps and solar photovoltaic (PV);
- by helping to manage the impact of increases in intermittent generation on the distribution network; and
- directly, for example by potentially reducing the carbon emissions associated with system balancing.

In line with recommendations from the Expert Panel, we have not quantified the total carbon saving associated with the Methods. However, we could provide this if it would be helpful.

Roll out of low-carbon technologies

The GBFM will facilitate the rollout of low-carbon technologies by releasing capacity more quickly and more cost-effectively than could be released through standard network reinforcement methods. Increasing DNO access to cost-effective flexibility such as DSR and storage will allow them to reduce peak demand on networks, thereby freeing up capacity and deferring the need for network reinforcement.

Once Solution 1 or Solution 2 has been established, it will allow capacity to be released more quickly than the next most efficient alternative, network reinforcement (see Appendix 5). We estimate that the use of flexibility will release network capacity at least four months more quickly than traditional reinforcement. This estimate is based on minimum timescales for reinforcing HV distribution networks, and the assumption that once the Solutions are up and running, they could allow the immediate release of capacity.

Faster release of network capacity is likely to allow more rapid adoption of low-carbon technologies, including heat pumps, EVs and solar PV. Releasing network capacity will therefore contribute to the Carbon Plan by facilitating emission reductions in the buildings, transport and electricity sectors.

Intermittent generation

The multi-party market (Solution 2) will also allow DNOs to manage the impact of intermittent renewables on the network. The multi-party GBFM will provide a means for DNOs to send price signals to the supplier which reflect the costs to DNOs of moving demand to times when the output of intermittent generation is high.

The rollout of intermittent generation will also be facilitated by the GBFM more generally, to the extent that it increases the supply of flexibility and allows the system to be balanced at lower cost.

Direct impact on carbon emissions

The Solutions will also have a direct impact on carbon emissions in three ways.

- To the extent that the Solutions increase the quantity of flexibility from DSR used by the TSO and others in the future, they may directly affect carbon emissions. We estimate that once the emissions associated with keeping large-scale plant available are taken into account, there could be an 70%-90% potential saving from every MW of reserve that can be provided through DSR instead of through large-scale plant, even if all the DSR is provided by back up diesel generators. These calculations assume the emissions intensity of diesel plant is 1.1 kg/kWh.
- The use of flexibility to release capacity rather than reinforcement will cause a small increase in losses due to the fact that networks will be operating at higher load factors. We estimate that a transformer replacement would cause losses to reduce from 0.23% to 0.21%. With the deployment of the Solutions, losses would remain at 0.23%.
- DNO access to flexibility will reduce the required amount of asset replacement. This will also help reduce emissions associated with the electricity sector by avoiding the embedded carbon associated with asset replacement.

4: Evaluation Criteria contd.

Financial benefits

Each Method is expected to reduce costs for DNOs by allowing network reinforcement to be deferred.

We have calculated these net benefits by comparing the Methods being trialled to the options currently available to DNOs: network reinforcement and bilateral contracting of flexibility. Further details on their estimation are presented in Section 3 and Appendix 5.

The net financial benefit at project scale of Method 1 is £23.5m and £80.0m for Method 2 between now and 2040. In line with guidance from Ofgem, these numbers have not been discounted.

There are likely to be significant economies of scale associated with the Methods. In particular, Method 2 involves upfront investment in a market platform. The costs of the market platform will not rise proportionately to the roll out of the Method. If the Methods were rolled out across GB, the benefits would rise to £255.6m for Method 1 and £866.9m for Method 2.

Network capacity released and replicability

As described above, Method 1 and Method 2 will release capacity on the distribution network more quickly than traditional asset reinforcement, which we estimate is the most efficient method currently used. Both Methods will do this by allowing DNOs access to flexibility which reduces peak flows on networks.

Analysis for the CLNR project, based on feeders representative of different types of load, at various voltage levels, suggests that 10% of domestic peak load and 5% of general load can be shifted without creating new peaks. Based on this analysis, we have assumed that 5-10% of load can be shifted, equating to 2-3MW of capacity that can be released per primary. Northern Powergrid has identified 20 primary substations suitable for inclusion in the trials. This means that the Methods could release 40-60MW of distribution network capacity at project scale.

To estimate the total capacity that could be released across GB through the Method, we first looked at the types of network that will be covered by the trial. The HV network covered by the GBFM trial comprises the following feeder types:

- Urban, High, Underground, Radial;
- Suburban, Medium, Underground, Radial;
- Suburban, Medium, Mixed, Radial; and
- Rural, Low, Overhead, Radial.

Based on the model developed by the Smart Grid Forum Workstream 3, these feeder types make up 67% of the total GB system.

We used the Workstream 3 model to assess the amount of flexibility (in effect DSR) that would be taken up by DNOs given the expected cost reductions associated with Method 1 and Method 2. Taking results only for the feeder types listed above gives us estimated capacity released of 925MW for Method 1 and 944MW for Method 2 by 2030. If we assume that the Methods could be applied at all feeder types, the capacity released across GB by 2030 would be 1.2 GW for Methods 1 and 2. For calculating the total GB-wide benefits, we have conservatively used only the figures relating to the feeder types included in the trial. However, it is highly likely that the Methods would be more widely applicable.

We estimate that the Methods could be rolled out across GB within two years of the end of the project. This would allow time to review the education and training requirements, to make enhancements to processes and tools for system design and planning, to implement any required changes to control room systems and possible changes of responsibilities in Consumer Operations, Regulation and Procurement. It also takes account of the time it might take to review the findings of the project and reach a decision to implement.

(b) Provides value for money to distribution customers

This section sets out the benefits that can be attributed to the distribution network. It also sets out how we have taken steps to ensure that the Second Tier Funding Request represents the best value for money to distribution customers.

Size of benefits and learning that are applicable to the distribution system

Both Methods being trialled aim to reduce the costs of flexibility services to DNOs. Increasing the efficiency of the provision of flexibility provides benefits for other parties, such as the TSO and suppliers. However, at £221.7m for Method 1 and £397.4m for Method 2, the overall benefits to DNOs alone are much greater than the level of funding being requested (£16.4m). These benefits make up 87% of the total benefits of Method 1 and 46% of the total benefits of Method 2. Again, following guidance from Ofgem, we have not discounted

4: Evaluation Criteria contd.

these net benefits.

Distribution customers will benefit from the reduction in costs to DNOs. Those customers that provide flexibility through DSR will receive the direct payments made to flexibility providers (though we note they may also incur a cost in providing this flexibility). To provide an indication of the scale of the direct benefits to providers of flexibility, we estimate the total payments received by flexibility providers at GB scale under Methods 1 and 2. These are £493.9m between 2017 and 2040 for Method 1, and £545.2m for Method 2 over the same timescale (undiscounted).

In addition a large proportion of the benefits of the GBFM that accrue to suppliers and the TSO will ultimately be passed on to distribution customers, since most electricity customers are also DNO customers. These benefits will reach distribution customers through lower bills.
Further, by working with Local Authority and Housing Associations (LAHAs) we are passing on some of the potential financial benefits associated with providing demand flexibility to the low-income customers that are hit hardest by distribution charges.

As well as providing benefits to distribution network customers, to enable these solutions, the project will also produce the following implementation tools, which will be useful to all DNOs.

- **Guidelines for use of DSR and storage.**

  - *Engineering guidelines and codes of practice for use of DSR by the DNO.* For example, the project will allow better understanding of the confidence that DNOs can apply to DSR in planning and will feed into the drafting of P2/7.

  - *Engineering guidelines and codes of practice for use of EES in a multi-party market.* The project will allow better understanding of additional needs associated with the use of EES resources in the flexibility market.

- **Implementation tools.**

  - *A set of operating frameworks for DNO-TSO sharing of flexibility*. The experience in the trial will be used to develop a set of operating frameworks that can be used by Northern Powergrid and other DNOs.

  - *An implementation roadmap for the multi-party market***.** This will set out all the actions that are required to implement the Method, including required regulatory changes.

  - *A set of detailed market rules***.** The market design used in the trial will be applicable at GB level.

  - *A prototype IT system for running the market.* The project will produce an IT system which allows the detailed market rules to be implemented.

Procurement processes

Northern Powergrid has undertaken a review of all of the major cost categories associated with this bid to ensure that best value for money is attained for DNO customers. As part of the project, an open competitive procurement process will be undertaken to ensure best value for money in respect of the development and delivery of the market platform. This option was chosen given it is a very material part of the overall cost of this project and because we confirmed, through the response to the RFI, that there are a number of suitable parties that could potentially provide this service.

There are a number of other specialist services that will also be required, given the technical and commercial expertise required to deliver the project. These services will need to be delivered for the duration of this four-year project, and there is significant learning that will be leveraged from both the bid production process and the CLNR project. Given this, the best value for money was achieved by ensuring that those resources were committed to the project by being a project partner and therefore making a material contribution to the external funding for this project. In addition, we have sought to limit the cost associated with these resources by leveraging the expertise where possible against internal Northern Powergrid resource.

Throughout the trial, we will be looking for technology partners to contribute significantly through discounted or waived prices for equipment.

4: Evaluation Criteria contd.

(c) Generates knowledge that can be shared amongst all DNOs

This section describes the incremental learning that can be gained from the trial, the applicability of the new learning to other DNOs, the robustness of the methodology and the treatment of IPR. Plans to disseminate learning are covered in Section 5.

Level of incremental learning expected to be provided by the Project

A range of LCN fund trials, (including the CLNR, Capacity to Customers, Low Carbon London and FALCON) are investigating the potential for DSR and other types of flexibility to reduce costs for distribution networks. These projects are demonstrating that there is customer appetite for participating in DSR schemes, and that technologies to enable DSR and storage can be deployed. However, it is also clear that accessing flexibility services can be difficult and costly for DNOs, because the current industry approach to accessing DSR and other flexibility services is fragmented across the value chain and flexibility services are contracted bilaterally.

This trial will build on the learning from current LCN fund trials by investigating the commercial frameworks which might allow this flexibility to be delivered in a more cost-effective way than the current bilateral framework. Both Method 1 and Method 2 aim to improve DNO access to flexibility and reduce the cost.

The Methods being trialled are innovative and have not yet been demonstrated. Our review of international evidence suggested sharing and trading of flexibility for use of DNOs has not yet been carried out (see Appendix 10). There is therefore likely to be significant incremental learning associated with these trials.

The applicability of the new learning to other DNOs

As set out in Section 4(a) above, our analysis suggests that the findings of this project could be directly applied to at least 67% of the GB network. This is based on an analysis of the number of primaries in GB of the type being included in the trial. However, it is highly likely that the learning will be applicable to other primary types.

Robustness of the methodology

The project will build on the initial experimental design process to set dimensions and conditions for the trials. This design process will allow the assumptions, the design dimensions and the applicability of the trial results to other DNOs to be investigated before physical trials proceed. The trial design will be peer reviewed by Durham University, to ensure that the engineering and social science outputs will be robust. Durham University will lead on the statistical interpretation of results, beginning by carrying out a detailed study of variation at a few of the chosen substations early-on in the project.

Further details on the modelling which will be carried out before the trials are presented in Appendix 7.

The design process will entail the following steps:

- to prepare for the trials, we will revisit design assumptions, undertake modelling to determine key parameters to include in the trial, approach flexibility providers, install network equipment and design other aspects of the trials that are common to Method 1 and Method 2;
- undertaking the network operator trial will involve system design, test and training, undertaking the winter and summer trial of the near term scenario, and the analysis and decision on whether to proceed to Method 2; and
- undertaking the multi-party trial will additionally involve integrating multiple parties and delivering the trading platform.

The experimental design and modelling will ensure that the results of the trials are robust and statistically significant. The process will also ensure that the trials are no larger or more complex than required. This will allow robust results to be delivered in the most cost-effective way.

At the conclusion of the trial the results will be analysed and checked against modelled outcomes. The comparison with modelled outcomes will allow divergences from expected results and the key drivers of these divergences to be identified. Again this analysis will be peer reviewed by Durham University.

The treatment of IPR

We do not intend to deviate from the default conditions for IPR.

4: Evaluation Criteria contd.

(d) Involvement of external partners and external funding

Northern Powergrid is joined on this project by seven strategic partners and five collaborators, each bringing a distinct set of skills and resources. Each partner, along with the external collaborators, either represents a participant in the GBFM or will support the delivery of the project.

Project Partners

- **British Gas**: British Gas is the largest energy supplier in the UK and will leverage the expertise developed and technologies installed during the CLNR project. British Gas has a key role to engage customers to deliver flexibility services to the GBFM primarily with commercial, SME and domestic customers. As part of Method 2, British Gas will leverage the expertise gained from the CLNR project to engage customers, install customer equipment to facilitate DSR and develop aggregation systems to despatch this resource.

- **Centrica Energy**: Centrica Energy brings energy trading and optimisation expertise to the project. Centrica Energy represents the energy trader and will operate as a purchaser of flexibility from the GBFM in Method 2 with the objective to optimise imbalance positions.

- **National Grid**: National Grid owns the onshore electricity transmission network in England and Wales and operates the entire transmission system throughout GB and the UK continental shelf. National Grid is the TSO and will purchase flexibility jointly with Northern Powergrid in Method 1. National Grid will procure services through Method 2 of the project only where National Grid makes the objective assessment that there is a potential benefit to the TSO from participating.

- **Elexon**: Elexon implemented and developed one of GB's largest energy industry codes, and continues to handle its day-to-day governance. Elexon represents the market operator and will take lead responsibility for the market design, market procurement and implementation process.

- **Durham University**: Internationally recognised leading researchers from Durham University will provide engineering, statistical and social science support to the project. Durham University will provide expert engineering peer review, market simulation and social research capabilities.

- **EA Technology:** EA Technology will provide engineering input to the project. EA will take lead responsibility for the design of the market trials and market modelling and will provide specialist project support across the workstreams.

- **Frontier Economics**: Frontier Economics blends economics with innovative thinking, hard analysis and common sense. Frontier Economics will take lead responsibility for economic modelling, evaluation and specialist project support across the workstreams.

In addition, representatives of the Twenties project from Dong Energy have already confirmed their support for the project and that they will sit on the project advisory board.

External Funding

The GBFM project will receive external funding which contributes to the delivery of the project. The external funding can be divided into three core components

- use of Northern Powergrid assets developed as part of the CLNR project;
- British Gas contributions from normal business operations (e.g. smart meters) and from the CLNR project (e.g. smart appliances and heat pumps); and
- external sources (e.g. specialist resources provided by the commercial aggregators and National Grid).

In addition, we investigated the potential for receiving additional external funding from a number of UK and EU external sources such as those detailed on the Energy Focus website (www.euenergyfocus.co.uk). No additional funding opportunities were available from these sources.

4: Evaluation Criteria contd.

Processes used to identify project partners

The GBFM project requires contributions and engagement from across the electricity industry. The project requires the following generic participants;

- DNO;
- TSO;
- supplier / energy trader;
- aggregators (including suppliers);
- customers;
- technology providers;
- market administrator; and
- specialist resource input covering the following areas - regulation, electricity market structures, power systems engineering, economics and social sciences.

The project has targeted existing CLNR project partners to leverage the expertise and resources developed by that project. The use of existing relationships will provide a significant intangible contribution to the project. In addition, Centrica Energy was included due to the interface with British Gas. National Grid and Elexon are included because of their specific roles in the electricity industry.

Consultancy assessment

A number of meetings were held with industry consultants at the beginning of 2012 to assess potential ideas for the LCN fund and to assess collaboration partners for the GBFM. The meetings were initiated either by the suppliers or by Northern Powergrid; all requests to discuss the LCN fund process were accepted by Northern Powergrid. This process resulted in the selection of Frontier Economics and EA Technology to assist with the bid production process and potentially with an enduring role in the project delivery phase.

Energy supplier assessment

The inclusion of another energy supplier in addition to British Gas was considered by the project. The advantages would be potential increased learning with a wider variety of participants. The disadvantages would be potential restrictions on knowledge dissemination and increased project complexity leading to increased risks to deliverability. Based on this, the project concluded British Gas would adequately represent the supplier category.

Technology providers

The provision of the market platform and customer technology will be purchased via either a tender process or vendor assessment process to ensure the project delivers value for money and obtains a broad level of input from a variety of suppliers.

Contractual arrangements between partners

All partners have signed a Memorandum of Understanding confirming their support for the project and have been closely involved in the bid production.

Idea evaluation process

The Tier Two assessment process had the following stages:

- internal peer review of potential project ideas;
- discussions with external consultants regarding possible Tier Two ideas;
- discussion with CLNR project partners regarding possible Tier Two ideas; and
- an internal selection process led by the Director of Asset Management and the Commercial Director of Northern Powergrid.

(f) GBFM: Relevance and timing

This section describes the relevance of the project to the move to a low-carbon economy, its use in future business plans and the appropriateness of its timing.

Relevant to the move to a low-carbon economy

In the move to a low-carbon economy, power flows across the distribution network will be increased by further electrification of heat and transport and continued growth of distributed generation.

Facilitating these new flows in a timely and economical manner requires additional tools, such as flexibility products, to release capacity on new and existing networks. By increasing the supply of flexibility, and reducing its cost, the GBFM project can help address these challenges.

4: Evaluation Criteria contd.

In addition, the GBFM may also help DNOs to manage the impact of intermittent renewables on the network, by providing a means for the DNO to signal the network costs of encouraging demand to follow intermittent generation output patterns.

Heat and transport electrification

Heat and transport electrification is likely to significantly increase the peak demand faced by distribution networks. The GBFM will help DNOs access flexibility such as DSR or storage to manage this increase in peak demand, and to reduce the need for reinforcements.

Heat and transport electrification is central to the move to the low-carbon economy and significant policy effort is planned to deliver them.

- The Government has committed in the Carbon Plan to encourage the deployment of low-emission vehicles before 2020 by supporting R&D and demonstration, and by providing £300 million of customer incentives. According to analysis by the Government's independent advisors, the Committee on Climate Change (CCC), most low-emission vehicles to 2030 will be electric.
- The Government also plans to introduce significant incentives for the uptake of heat pumps. The Carbon Plan projects that more than 130,000 low-carbon heat installations will be installed by 2020 as a result of the Renewable Heat Premium Payment and Phase I of the Renewable Heat Incentive. Again, according to analysis by the CCC, most of these installations are likely to be electric heat pumps. According to the Carbon Plan, electric storage heating may also play an important role.

In the 2010s, heat and transport electrification policies are likely to create challenges for distribution networks in areas where the rollout of EVs are clustered. By the 2020s, for carbon targets to be met, both types of technologies will need to be widespread. The GBFM project will consider the impact of both clustered and widespread rollout of electric heat and transport technologies, by simulating conditions that represent expected levels of rollout in the near term, 2020 and 2030.

The increase in embedded and intermittent generation

There are two issues for DNOs associated with the increase in distributed and intermittent generation.

- the increase in locally connected generation will increase power flows on distribution networks; and
- variability of largely remote generation may change the local pattern of consumption.

Generation connected to the distribution network, including domestic micro generation, will increase the magnitude and complexity of flows on the network. For example, Northern Powergrid has observed that high PV density can double the voltage swing on a network, eating up twice as much of the +10%/-6% permissible tolerance and, with conventional solutions, requiring twice the infrastructure. The project will allow DNOs to access flexibility services from storage, DSR and from embedded generation to help manage these flows.

In addition, the increase in intermittent electricity supply from renewables may change the pattern of demand on the network, to the extent that customers can be encouraged to demand more electricity when output from intermittent renewables is high. The project will allow DNOs to manage any additional peaks associated with this demand.

The Government's 2020 renewables target is likely to require around 30% electricity from renewable sources by 2020. To meet the 2020 renewables target, 20% of electricity is expected to come from wind generation by 2020 and 1% from solar PV (DECC, 2010, *National Renewable Energy Action Plan*) . All of the PV generation and much of the onshore wind generation is likely to be connected directly to the distribution network. Strong incentives are already in place to encourage investment in these technologies.

In the 2010s, these policies are likely to create challenges for distribution networks in areas where embedded generation is clustered. During the 2020s, the penetration of intermittent generation, alongside relatively inflexible generation such as nuclear, will increase significantly. Analysis published by the CCC suggests that by 2030, wholesale electricity prices may often be driven by wind output (CCC, 2010, *Fourth Carbon Budget*). To the extent that these price signals are passed on to customers by suppliers, the distribution network may face new and less predictable demand peaks. The project will simulate conditions that represent these expected levels of intermittent and embedded generation in the near term, 2020 and 2030.

4: Evaluation Criteria contd.

Used as part of future business planning

If the Methods trialled in the project prove successful, Northern Powergrid would factor the flexibility that could be accessed through this market into business plans. For every kW of flexibility that can be accessed through the GBFM, some network reinforcement could be deferred. Part of this project is to understand the confidence we place in flexibility, to understand the relationship between contracted and credited flexibility: for example, for multiple conventional gensets, 3kW of connected generation defers 2kW of network reinforcement. To the extent that the GBFM allows Northern Powergrid and other DNOs to access more flexibility and less costly flexibility, DNO costs in future business plan submissions are likely to be reduced.

The need for network reinforcement would be lower, but not insignificant, in the absence of the full expected increase in renewable generation and low-carbon technologies. The fact that these technologies may cluster in certain areas means that even at low levels of overall rollout, challenges will be faced by DNOs in some areas. There are instances already of DNOs experiencing power quality and voltage issues. Most of the voltage complaints that Northern Powergrid receives are now for high volts, although the consequential reinforcement for diffuse generation has so far been minimal. However, developers proposing generation often face material costs to address voltage rise issues, and developers proposing heat pumps often face material costs to address power quality issues. While the potential for domestic DSR is likely to be dependent on the rollout of low-carbon technologies, there is already substantial potential for DSR from I&C customers. The GBFM could help DNOs access this DSR potential. Access to more and lower cost flexibility through the GBFM would therefore help DNOs reduce costs and defer network reinforcement, even in the absence of successful climate change policy.

Adopting a market approach to obtaining flexibility resources as an alternative to network reinforcement is likely to have important implications for the distribution network business. A decision to obtain security of supply by using flexibility resources as an alternative to using physical assets with known characteristics will not be taken lightly and it would not be sensible to do so without first understanding what is required to prepare the business. A set of activities are required in the GBFM project to define what is required to move from the current position to the point at which the DNO is ready to use flexibility resources effectively and safely. These activities are set out in Appendix 9.

Appropriateness of timing

The GBFM project will contribute directly to the actions identified in DECC's recent publication on electricity system policy (DECC, August 2012, *Electricity System: Assessment of Future Challenges*). In particular it will:

- trial commercial arrangements aimed at encouraging the development of interactions between different users of flexibility; and
- increase understanding of the barriers to deploying storage and how these may be overcome through the development of innovative commercial arrangements.

As set out in Section 6, detailed planning has been carried out to ensure the project can be implemented from 2013. Undertaking the project from 2013-2016 will allow the Method, if it is demonstrated to have a net benefit, to be rolled out by the end of this decade. As described in section (a), there is already potential to reduce costs by allowing DNOs to access flexibility in a less costly manner. Given the numbers of heat pumps, EVs and the penetration of intermittent and embedded renewables expected by 2020, there will be an even greater role for the GBFM to reduce costs to distribution customers by the end of this decade.

The timing of the trial will also allow it to inform electricity market developments in GB and Europe. In particular, we will identify changes in the market arrangements occurring over the next few years that will or could interact with a future full-scale GBFM. Specifically, we will identify and examine the potential interactions in the following areas.

- We will identify how a full-scale GBFM would interact with the current GB market arrangements, specifically the BSC and imbalance settlement. This would include a summary of potential BSC Code Modifications that could be developed to support a multi-party flexibility market.
- We will consider European Network Codes, in particular those that may constrain the future form of a full-scale GBFM such as CACM, Demand Connection and Balancing Network Codes. European Network Codes are due to be finalised and made legally binding during 2014. Each Network Code then allows for a period for aspects of the code to be implemented, for example imbalance settlement is likely to move towards increasing harmonisation over a period of years following 2014.

4: Evaluation Criteria contd.

- The Government's Electricity Market Reform proposals are being developed and the design is likely to be finalised during 2013 with first payments possible from 2018. The timing of the GBFM project will allow us to consider whether and how payments for Demand Capacity would interact with a full-scale GBFM.
- Ofgem's Significant Code Review of energy balancing was launched in 2012. The GBFM will feed into this, in particular on how payments in the GBFM might feed through into imbalance prices.
- Ofgem's Smart Markets initiative is focused on a number of potential market improvements. The GBFM will complement this work, in particular supporting the policy development to increase the availability of DSR.

The timeline for the future policy developments identified above are potentially subject to change and are highly dependent on a number of external initiatives.

4: Evaluation Criteria contd.

4: Evaluation Criteria images, charts and tables.

Evaluation Criteria Images

Section 5: Knowledge dissemination

☐ Put a cross in the box if the DNO does not intend to conform to the default IPR requirements

5.1 Stakeholder engagement and learning dissemination

Stakeholder engagement and dissemination of knowledge will be a core part of the project.

The GBFM can deliver significant value by understanding the requirements of all potential users of a national market at the design stages of the GBFM. This will enable it to be designed to best meet those needs. The GBFM project believes an industry-wide engagement process for all industry participants is critical to support any future development of a national market.

It is both necessary and desirable to raise awareness of the project and its key outcomes, particularly among potential market participants and the policy and research community, as well as with a wider audience including business and community groups and forums, commercial enterprises and the general public. This is required to ensure that the output of the project will be the best fit for the potential users of the market. Engagement and communication with stakeholder groups will aim to raise their level of understanding and to encourage them to contribute information and views. This will be an active process which will be achieved by focusing, tailoring and packaging the message for each particular target audience.

Stakeholder engagement

As described in Section 2, the project will invite contributions to the GBFM from the following nine groups of potential market participants and other core stakeholders.

•Potential market participants:
- networks (DNOs, TSO);
- suppliers, generators and energy traders; and
- aggregators and large customers.

•Other core stakeholders:
- government and regulatory bodies;
- academic institutions;
- consultants;
- technology vendors;
- related associations and organisations e.g. consumer representatives; and
- market operators.

Our engagement will include activities such as:

• a PR campaign to raise awareness of the project's brand;
• road-shows and working groups to capture input at the design stages of the GBFM;
• consultation processes; and
• trial observation opportunities.

A knowledge dissemination process will run in parallel to this engagement.

Figure 5.1 sets out a timeline for this work.

PR campaign

A PR campaign will be instigated to raise awareness of the project's brand. This campaign will aim both to attract stakeholders to the working groups or seminars and to increase their familiarity with the aims and design of the GBFM as it develops. This is likely to use industry media, social media such as project partners' twitter accounts, and networking events.

Road-shows and working groups

We propose to have road-shows and working groups or seminars at three stages of the market design process. These events will cover both Method 1 and Method 2.
• **Introductory road-shows.** We will begin by holding introductory road-shows. These will be open to all to all of the stakeholder groups identified above, and will focus on communicating and eliciting feedback on the high level GBFM concept.
• **Working groups or seminars for market participant requirements.** The introductory road-shows will be followed by a set of working groups or seminars for the five potential market participant groups, as well as a consolidated event for each Method, to allow attendees to view the initial design requirements across

5: Knowledge dissemination contd.

the sector. The other core stakeholders (listed above) will be invited to the consolidated events. The aim of this engagement will be to gather information on the requirements of each type of market participant, to feed into the design of the market model.

- **Review working groups.** A series of up to three review sessions will then be held to allow all market participants to provide feedback on the resulting detailed set of market rules. Comments on the detailed market design will be carried forward to the platform development.

These working groups or seminars will inform the development of the new commercial arrangements being trialled in Method 1 and Method 2.

We will also have consolidated workshops/conferences at further points in the process to discuss:

- emerging results of the evaluation of Method 2 at the decision point;
- emerging results of the final evaluation and draft recommendations on Method 1 and Method 2; and
- draft roadmaps for implementation of Method 1 and Method 2.

All groups will be invited to these workshops. The aim will be to communicate emerging thinking and to allow stakeholders a chance to respond before final decisions are made.

Consultation processes

Running parallel to the working groups will be a written consultation process. Again, this will cover both Methods. There will be three main parts to this.

- **Market design**. Emerging thinking following the working groups and seminars will be reported on the project website, and emailed to all participants after each set of workshops has been completed. This will allow stakeholders to feed back comments at three points during the market design process.
- **Initial evaluation**. An initial evaluation of the market design will be published to inform the decision point on Method 2. This will be posted on the website and emailed to all participants that have attended a workshop or registered an interest in the project, to elicit written comments on our assessment of the potential costs, benefits and barriers to Method 2.
- **Final evaluation, recommendations and roadmaps.** We will publish our emerging findings on the evaluation, recommendations and roadmaps for consultation before the project close. This will ensure that our final reports can be informed by stakeholder views.

Trial observation opportunities

We will also welcome feedback from stakeholders on the trials as they proceed. This will be important to allow us to review the design of the trials, and the commercial arrangements that they are trialling, after the first winter season.

To facilitate this, during the Method 2 trials, we will establish a `viewing platform' which will allow stakeholders to monitor trades in the market, and to look at aggregated data on trades that are occurring.

We will also run a GBFM simulation day. This will allow participants across the industry to simulate participation in the market.

Dissemination

In parallel to the engagement process, we have a process for knowledge dissemination.

The knowledge dissemination will be aimed at both internal and external parties and customised information will be provided which is appropriate for each group, where necessary. Our message will be clear and simple and will address the questions posed in the Learning Outcomes.

Dissemination will focus on potential market participants, other core stakeholders and a wider group of interested parties, such as for example other LCN fund projects and local groups (e.g. Local Enterprise Partnerships, Chamber of Commerce).

5: Knowledge dissemination contd.

Targeted communication to potential market participants and to the research and policy community will consist of the following:

- The project and its results will be presented as they become available at relevant conferences and events and through the use of webinars, and cross party workshops will be held.
- A project website will be set up which will be regularly updated to reflect project achievements and will include podcasts and FAQs. It is intended that the existing website www.networkrevolution.co.uk will be expanded to include the GBFM project.
- Learning will be published in scientific and industrial journals, where appropriate.

External communication will include the following.

- Press releases will be issued targeting various media to inform about the start and ongoing achievements of the project.
- Ongoing announcements will be via a newsletter and updates to the project website.
- Promotional material will be produced including leaflets for further distribution through partners' communication channels and networks.
- Social networks (such as twitter, Facebook and LinkedIn) may be used to spread learning from the GBFM to a wider audience.
- A common project brand will be used among all partners, such as the project logo and the project presentation, ensuring uniformity of the GBFM appearance to third parties. To exploit synergies it is intended that the Customer Led Network Revolution logo and branding will be used.
- Further opportunities may arise where it is possible to promote the project in a new area and raise awareness with a new audience. These opportunities may include seminars, symposia, exhibitions, and presentations which are directly or indirectly related to the project.

Responsibilities

Workstream managers

It will be the responsibility of each of the workstream managers (market design, delivery and trials, customer engagement, network technology and learning and dissemination) to produce a consolidated output report on a quarterly basis which will detail the knowledge gained during the period against the Learning Outcomes and in particular which questions have been answered.

Communications Manager

The communications manager will support the project by planning, establishing and implementing effective and high quality knowledge management processes, strategies and systems for information gathering, documentation, and dissemination of project learning and will be responsible for the following key deliverables:

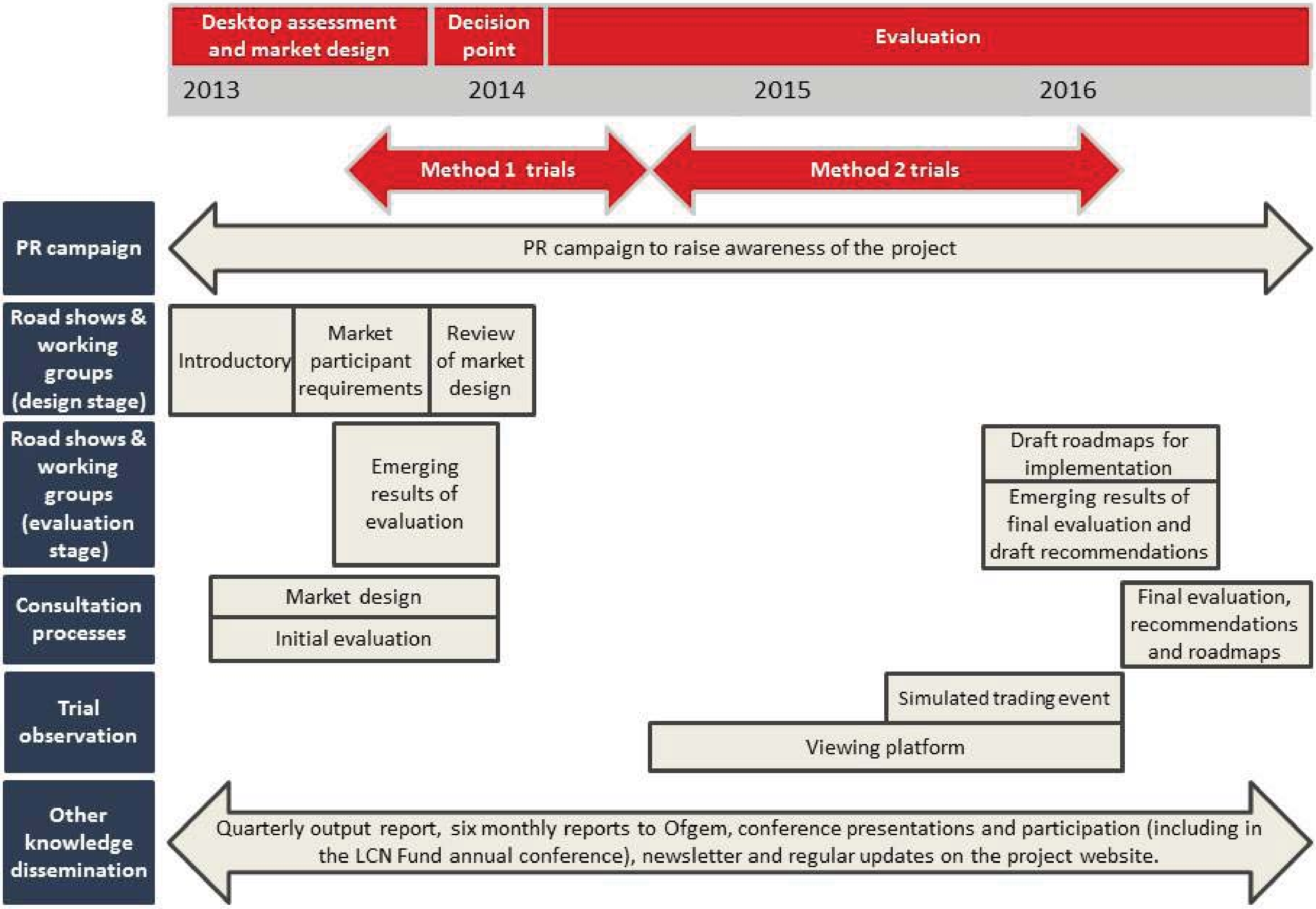
- analysing reports and writing summaries in an appropriate style and language;
- writing text and web summaries of research for a variety of audiences;
- synthesising across workstreams to draw out messages for a variety of audiences; and
- organising and participating in conferences, seminars and training workshops.

5.2 IPR

This project will be undertaken in accordance with the CRC13 Governance Document including IPR and reporting requirements.

5: Knowledge dissemination images, charts and tables.

Figure 5.1 Timing of stakeholder engagement



Section 6: Project readiness

Requested level of protection require against cost over-runs (%).

Requested level of protection against Direct Benefits that they wish to apply for (%).

By leveraging the experience gained from the CLNR project, using tried and tested internal governance frameworks and partnering with world class organisations, we believe we can successfully deliver this project.

This section will provide an account of:

- why the project can start in a timely manner;
- how the costs and benefits have been estimated;
- the measures employed to minimise the possibility of cost overruns or shortfalls in direct benefits;
- the processes in place to ensure the accuracy of information in the bid (i.e. verification of all information included in the proposal);
- how the project plan would still deliver learning in the event that the take up of low carbon technologies and renewable energy in the trial area is lower than anticipated;
- the processes in place to identify circumstances where the most appropriate course of action will be to suspend the project, pending permission from Ofgem that it can be halted; and
- the project governance and project management methodologies.

6.1 Why the project can start in a timely manner

Northern Powergrid can ensure the GBFM project starts in a timely manner by bringing together the following components:

- pre project authorisation foundation activity;
- working with project partners that cover the electricity value chain;
- drawing on support from external collaborators such as the Twenties project, who will not only participate in the project but will also sit on the project advisory board;
- working with external suppliers that contribute a wealth of knowledge that can be leveraged for the benefit of the project; and
- ensuring there is strong executive support from each partner with a clear commitment to ensure the project successfully delivers the key milestones and outputs.

Pre project authorisation foundation activity

Project readiness preparation will continue after the bid submission in August 2012 through to the decision point in November 2012. The key project readiness activities will involve 1) the identification of named resources, 2) internal communications with key stakeholders e.g. the Northern Powergrid procurement and legal teams and 3) continual status updates with the project partners and collaborators.

Project partners

The nature of the project and the ambition of the multi-party trials dictates the requirement for a broad cross section of partners from the electricity industry and from industry experts. The project brings together a strong consortium of project partners which ensures each actor in the GBFM trials is represented by a project partner or an external collaborator. The selection of project partners was based on leveraging relationships developed during the CLNR project, building new partnerships with natural participants in the GBFM (e.g. National Grid) and selecting external collaborators (e.g. Asda). The partner selection process involved Northern Powergrid and our bid production partners, ensuring the project evolved collectively.

The bid production process was a collective exercise with all the partners. This approach ensured that the project's aims, scope, deliverables and plans are collectively understood. This understanding ensures a high degree of confidence can be ascribed to the project plans and the roles and responsibilities of each

6: Project readiness contd.

partner. All project partners are signatories to a Memorandum of Understanding with Northern Powergrid which ensures explicit recognition and commitment to the project deliverables. Each of the project partners is of sufficient scale that the required resources can be allocated to the project, mitigating resource allocation risk. The project readiness planning will continue prior to the LCN fund award to ensure the project is positioned to commence during January 2013 as planned.

Support from external collaborators, suppliers and executive sponsorship

In addition to the project partners the project will be supported by:

• External collaborators who will undertake two key roles; 1) participation in the project at both the design and trial stages and 2) providing representation on the advisory board supporting both the project director and the executive sponsor group.

• The external suppliers will undertake critical roles within the project taking responsibility for delivering the multi-party trading platform for the trials and supporting customers with delivering flexibility to the GBFM.

• The project director will report to the executive sponsor group. The executive sponsor group demonstrates an unambiguous signal of support for the project by each organisation by its senior management. The executive sponsor group will provide project direction advice and can mobilise internal resources to ensure the project delivers the planned outputs.

6.2 Estimation of costs and benefits

The project costs have been constructed by Northern Powergrid with input from project partners and suppliers and measures are in place to minimise the possibility of cost overruns or shortfalls. The GBFM project costs can be divided into three broad components:

1) mandays from project partners;
2) customer subsidies for the market trials; and
3) supplier costs associated with the trading platform, customer flexibility technology and infrastructure e.g. DNO dispatch systems and supplier aggregator processes.

6.3 Measures in place to minimise cost overrun

Specific contingency items have been built into the cost model to protect against cost increases. The cost model has been reviewed by Northern Powergrid's finance team.

The project budget will be managed by Northern Powergrid's finance function, using systems and processes developed during the CLNR project. The management of project costs will be a standard agenda item on the GBFM steering group's agenda. Best practice requires that the project delivery team works in unison with the finance teams, ensuring the financial reporting and forecasting processes mirror the project operations day by day. The project management methodologies will ensure these processes are embedded in the daily operations of the project. The rigorous approach to project governance should ensure that costs will not overrun the estimates in the bid.

For the CLNR project Northern Powergrid were granted an exemption from the requirement to keep the funds from the Second Tier Funding for this project in a separate bank account. We requested this exemption as it was deemed more straightforward to use our existing accounting systems to isolate income and expenditure on the CLNR project rather than try and deal with transfers between the multiple bank accounts operating in the Distribution businesses. It is anticipated that we would take a similar approach with GBFM. Northern Powergrid will communicate with our auditors Deloitte LLP to inform them of the project's requirements should the bid be successful.

Measures in place to minimise the largest cost risks facing the project are:

• *Delivery of the multi-party trial platform.* The bid has mitigated this risk by running a Request for Information during the summer (2012) to ensure a robust financial estimate is included in the bid.

• *Mandays required by the project partners to deliver key milestones.* The bid production process has illuminated the scale of resource activities required. This process has then been scaled to reflect the project delivery phase.

6: Project readiness contd.

The project will allow DNOs to defer reinforcement and will therefore save costs. The net benefits of the project have been estimated by Frontier Economics and EA Technology. While there is inevitably a large degree of uncertainty over the net benefits, conservative assumptions have been used to ensure that the estimates are reasonable. Further details are presented in Section 3 and Appendix 5.

6.4 Verification of information in the proposal

All information included in the bid is accurate to the best of our knowledge. Cost estimates have been provided by project partners and through the RFI process on the market platform. We have used external consultants to help set the required parameters of the trial. Details are provided in Appendix 7 and this work has been reviewed by Durham University. We have also used external consultants to estimate the net financial benefits. The assumptions underlying this estimation are set out in Section 3 and Appendix 5. Throughout, we have identified clearly where we have had to rely on assumptions in the absence of accurate information or evidence.

6.5 Risks around low-carbon technology take up

The project would still deliver learning in the event that the take up of low-carbon technologies is lower than anticipated. The project is not reliant on the strong levels of take up of low-carbon technologies in the trial area:

- The project will draw on customers that already have low-carbon technologies and are participating in the CLNR project. These include 100 customers with either heat pumps or smart appliances.

- A significant part of the DSR in the project will be provided by I&C customers. These customers can provide DSR already and do not require low-carbon technologies.

6.6 Processes to end the project

Processes are in place to identify circumstances where the most appropriate course of action will be to suspend the project, pending permission from Ofgem that it can be halted.

The GBFM project plan has a clear decision point during November 2013 to assess whether the benefits expected from the GBFM market justify the implementation of the multi-party trials. The desktop assessment and the network operator trials will have been completed at this stage and will enable an informed decision to be made regarding the costs and benefits associated with a GB Flexibility Market. The decision will be assessed internally by the project and will be presented to Ofgem for final approval.

The project steering group will take responsibility for assessing the project on an ongoing basis to ensure our distribution customers receive value for money; any decision to suspend the project would be presented to Ofgem for final approval. The project will draw on the experience from the CLNR project to ensure project issues, risks and decisions are addressed on a timely basis and by the right people to ensure the project delivers its key aims and outputs as set out within this bid.

6.7 Project governance and project management methodologies

The governance structure will ensure that the project is managed to deliver the key milestones and SDRCs, and maximises learning for distribution customers and all project participants. The project director, Jim Cardwell, Head of Regulation and Strategy, will take primary responsibility for project direction. The project director will be supported by:

- an executive sponsor group comprising senior management representation from each partner;
- a project steering group comprising each partner with project delivery responsibility and a Northern Powergrid technical assurance coordinator;
- a project advisory board comprising external collaborators and industry experts; and
- a project delivery manager and project management team comprising both Northern Powergrid and partner colleagues.

The groups will be coordinated by the project director and project delivery manager.

The project plan allocates a significant amount of resource to the mobilisation period and the project management methodologies. This builds on the experience gained from the CLNR project and ensures a foundation is developed for the project which supports the operations of the project on a day to day basis.

6: Project readiness contd.

The governance structure and project management arrangements to be deployed on the GBFM are designed to ensure that the project achieves its specified Learning Outcomes and intended benefits and that these are appropriately shared with customers and relevant industry participants.

It will do this by clearly communicating the project vision to all participants, identifying relevant and timely project milestones and delivering these through robust planning, timely and effective decision making, resolution of issues, control of changes and mitigation of risks.

The bringing together of companies with different ways of working and different cultures requires the application of common project management and behavioural principles to ensure that the project is mobilised efficiently and achieves its required outcomes in respect of timing, cost and quality. The key themes for the values and behaviours applied throughout this project will be the following.

Understanding the project goals

- Project vision - All team members will be made aware of the project vision and have a view of what the vision means to customers and to the partner organisations.

- Learning outcomes - All team members will be made aware of all the Learning Outcome expectations and how their particular workstream(s) contribute to the big picture.

Planning to succeed

- Create and communicate the high-level plan - The high-level project plan will be communicated to all project participants by the project delivery manager.

- Adopt a stage planning approach - Planning by stages allows the project steering group to more effectively control the time cost and quality requirements of discrete elements of the project relative to the overall goals, to assess project success at pre-determined intervals and to ensure that key decisions are made prior to the detailed work needed to implement them. The workstream managers will plan project stages for steering group approval.

- Manage the dependencies and critical path - The workstream managers will fully understand the critical path for their workstream stages and for the whole project and work with the project delivery manager to actively manage the dependencies between workstreams.

- Understand project tolerances - All project team members will understand the tolerances within which they are working and the extent to which a potential deviation from plan could affect the quality of the Learning Outcome, the achievement of SDRCs or the cost of the project. The tolerance frameworks will be created by the project delivery manager and signed off by the project steering group.

- Understand roles and responsibilities - All workstream managers will ensure that all their team members understand how the achievement of their task contributes towards the overall Learning Outcome of their workstream.

Keep focus on the outcomes

- Monitor and control - The workstream managers will monitor and control activities to remain on target to achieve the overall time, cost and quality requirements of their workstream.

- Report on progress - The project managers will report on progress in sufficient detail to enable the project delivery manager to manage the dependencies between workstreams and to manage and report to the project director and the project steering group on progress against the overall project goals.

- Managing issues, change and risks - The workstream managers will assess the impact of any issues and risks and any proposed changes to the timing, scope or cost of planned project activity and escalate these to the appropriate project level.

Make decisions at the right level

- Clearly defined criteria for reporting and escalation - Changes, issues or risk that result in impacts within the tolerance agreed by the project steering group willl be made at workstream or project level but changes that have the potential to threaten the achievement of the project direction will be escalated to the project steering group.

6: Project readiness contd.

• Clearly defined criteria for technical assurance - Key technical decision points will be identified for steering group review and approval. The steering group will use the project advisory group and/or the Northern Powergrid technical assurance coordinator (TAC), as appropriate, if a wider perspective or additional expertise is required.

Work together to achieve continuous improvement

• Seek and apply project learning - The GBFM project team will operate as a learning organisation to encourage and foster a culture of mutual learning and continuous improvement by promoting a process that captures all lessons learned during and at the closure of each project stage.

• Communicate to the team - Ensure actions, decisions and learning from whatever source they arise are effectively communicated to all relevant participants via a shared workspace.

Stage planning

The project director will direct the project and report to the executive board. Day-to-day control on a stage-by-stage basis will be delegated to the workstream managers via the project steering group and the project delivery manager. The workstream managers will be given clear parameters of the delegations for each project stage and will convert the high-level requirements into detailed stage plans for approval by the project steering group. The stage planning documentation will consist of the following:

• a stage plan in the form of either a gantt chart or similar displaying the timings and the tasks associated with this stage;

• an overview of any impact on the overall project plan and confirmation, or otherwise, of the key project milestones and the overall SDRC milestones;

• an update to the issues register with any issues currently affecting delivery of the stage;

• an update to the risk register with any risks foreseen for this stage;

• a stage initiation document containing the following information:

- a list of the products to be delivered during the stage (i.e. the product breakdown structure) including the products and learning to be disseminated;

- a description of each product;

- a description of the quality requirements and tolerances for each product and a description of how quality will be assured;

- the stage costs and resource requirements;

- limits of delegated authority on time, cost and quality (including, where appropriate, the need to refer to the TAC or another individual to sign off variations without recourse to the full project steering group);

- identification of any dependencies between the products to be delivered in this stage and products in other workstreams or stages;

- a description of how the stage will be managed and controlled, including how any lessons learned from elsewhere in the project can be applied in this stage;

- a plan for recording and disseminating learning, whether gained formally (e.g. as products) or informally (e.g. in the process of delivering the products);

- the issues currently affecting the stage delivery and how these will be addressed; and

- the risks that have been foreseen for this stage and how these may be mitigated including proposals for contingency.

For a product to be deemed to be delivered, it must be checked against the product description (including quality/tolerance criteria), and signed off by the project steering group (including the TAC).

6: Project readiness contd.

Once all the products have been delivered and all tasks completed, it is essential that the stage is authorised to close. To gain approval for the closure of the stage, the workstream manager must present to the project steering group for approval a stage end report including the following:

- a completed stage plan;
- an update to the overall associated workstream plans and confirmation, or otherwise, of the future key SDRC milestones;
- evidence that the stage has been delivered to cost and all products for the stage have been delivered within the required quality tolerances;
- evidence that product records have been updated and the products and associated documents have been correctly filed;
- evidence of effective dissemination;
- an update to the risk and issues registers for all entries relating to this stage ensuring that these registers include the impact that any departure from plan in this stage may have on adjacent stages/workstreams; and
- an update to the lessons learned log to report on any new lessons learned throughout the stage for future learning for the project team.

Delegations of authority

A structured approach to delegations of authority will be applied to ensure that technical and business approval decisions in the project are taken at the most appropriate level, particularly in relation to pre-determined decision points and also in response to issues, risks and changes that arise at the project level or during the course of a workstream stage. For the workstream activities, decisions will be made at the right level by the workstream managers having a clear understanding of the outcomes to be delivered and the allowable cost, quality and timescale tolerances for the stage that they are managing, which will be clear to all workstream participants after the stage initiation has been approved by the project steering group. The steering group decisions required at pre-determined decision points will, in effect determine the stage boundaries, so those decisions will usually be made at the opening and closure of each stage. The steering group will use the project advisory group, as appropriate, if a wider perspective or additional expertise is required. Once a stage has mobilised, any issues, risks, or change proposals that arise can be approved as follows:

- **Level 1 - Workstream Level** - if the decision results in an impact within agreed tolerances and there are no consequential impacts on any other workstream then it shall be dealt with by the workstream manager, consulting with any individual named during stage initiation.
- ***Level 2 - Project Level*** - If, in the opinion of the workstream manager having consulted with the technical assurance coordinator, there is a potential impact on another workstream it shall be escalated to the project delivery manager. The project delivery manager may prepare a mitigation plan for immediate implementation or escalate to Level 3.
- ***Level 3 - Project Steering Group*** - If the agreed cost, time or quality parameters are potentially impacted but do not threaten achievement of the SDRCs, the project delivery manager will prepare a mitigation plan for review by the project director and approval by the project steering group.
- ***Level 4 - Executive Board*** - For issues that threaten the achievement of the SDRCs or the strategic direction of the project, the project director will prepare a mitigation plan for executive board review and approval.

The management of decision points, risks, issues and changes

For the GBFM project, the distinction between decision points, risks, issues and changes is as follows:

- A decision point is a point in the project where future direction cannot be given until earlier pieces of work have been completed and signed off. It is therefore necessary to identify such pre-determined decision points as appropriate, where possible, to identify some, if not all, of the possible options.

6: Project readiness contd.

- A risk is an uncertain event or set of events that, should it occur, will have an effect on the achievement of the project objectives. A risk is measured by a combination of the probability of a perceived threat or opportunity occurring, and the magnitude of its impact on objectives.
- An issue is an event that has happened, was not planned or foreseen, and requires management action to resolve if the project is to achieve the project objectives.
- A change is a product deviation outside the predetermined parameters for time cost and quality, which may arise as a result of an issue or risk, and which needs review and approval in respect of the acceptability of its impact on the project objectives.

Issues, risk and changes will be managed through the use of registers.

Decision Points

The project is structured into stages and each stage will contain identifiable decision points where outcomes from that stage influence the direction and plans for subsequent stages. These dependencies between stages and the relevant decision will be clearly identified in the stage plans.

Risks

The approach to risk management to be taken on the GBFM project is to ensure that:

a) risks are notified as soon as they are identified;

b) the risks enter a formal risk management process;

c) the risk level, in terms of potential impact and impact consequence and the mitigation approach to be taken is approved at an appropriate level, commensurate with the level of risk; and

d) the risks and their associated mitigation plans are reviewed at the appropriate level and at appropriate intervals.

Risks are categorised in accordance with methodology adopted by Northern Powergrid, as set out in the Code of Practice RKK/002/002 - Northern Powergrid Risk Management Process and shown in Figure 6.1.

The project steering group is responsible for providing guidance and clarity on new RED and AMBER risks and on risks that remain at this status after mitigation. Where risks transpire to be an issue or actual event which may exceed project tolerances, the project steering group is responsible for escalating such issues and potential solutions to the executive board. The project director in conjunction with the project delivery manager will agree the budget identified for individual risks which will directly affect the usage of any contingency budget.

The executive board are responsible for providing guidance and clarity on RED risks including those risks which have transpired into an issue or event and the mitigation plan would exceed project tolerances.

Issues

The issues management process ensures that any emerging project issues that have the potential to impact on the project outcomes and associated time, cost and quality criteria are identified early, appropriately impact assessed and the contingency plan is escalated to the appropriate level within the project hierarchy for review and approval. It operates with a similar notification process and register as the risk management process.

Changes

The change management process ensures that all material changes to scope, cost or timing of particular project products that fall outside pre-determined parameters agreed with the project steering group are reviewed and approved after a comprehensive review of their impact on the relevant project criteria including the Learning Outcomes of the project. It operates with a similar notification process and register as the risk management process and the change register therefore keeps track of all approved project changes, the reasons for the change and their impact on the project.

6: Project readiness images

Figure 6.1 Northern Powergrid risk management process

Probability	It is judged to be **near certain** that the risk will occur (70% < probability <100%)	High	H	NH	LH	MH	HH
	It is judged to be **probable** that the risk will occur (40% < probability < 70%)	Medium	M	NM	LM	MM	HM
	It is judged to be **possible** that the risk will occur (1% < probability < 40%)	Low	L	NL	LL	ML	HL
	It is judged to be **improbable** that the risk will occur (probability <1%)	Negligible	N	NN	LN	MN	HN
				N	L	M	H
				Negligible	Low	Medium	High
				Should the risk occur it is judged that the impact on the programme would be **negligible**	Should the risk occur it is judged that the impact on the programme would be **marginal**	Should the risk occur it is judged that the impact on the programme would be **critical** (or opportunity would be **significant**)	Should the risk occur it is judged that the impact on the programme would be **catastrophic** (or opportunity would be **tremendous**)
				Impact			

Section 7: Regulatory issues

☐ Put a cross in the box if the Project may require any derogations, consents or changes to the regulatory arrangements.

The project partners have assessed the regulatory implications associated with the delivery of the GBFM project. Specifically, the partners have assessed whether the project may require a derogation, licence consent, licence exemption or change to the current regulatory arrangements.

The regulatory areas that could be impacted by the project include:

- existing industry DSR frameworks e.g. STOR;
- issues associated with a DNO-owned energy storage asset participating in the power markets;
- ER P2/6 Security of Supply;
- Interruptions Incentive Scheme; and
- ESQCR legislation.

In addition, the project will interact with existing and future GB electricity market arrangements.

Existing industry DSR frameworks

Our aim is to, where possible, minimise the impact on any of the TSO's existing arrangements for the contracting of flexibility (such as STOR or Fast Reserve).

At this stage, we therefore do not consider that any derogations due to the interactions with STOR or other DSR frameworks will be required.

Trading energy from storage

Northern Powergrid will trade energy from 2.85 MW of storage in this project. At this stage, we do not consider that this will require a derogation, since we understand that this will be permitted via the following existing exemptions:

- the storage provides no more power than 10 MW per installation or has a net capacity of less than 100 MW and provides no more power than 50 MW per installation; and
- the storage investments and turnover do not exceed `*De Minimis'* limits specified in standard conditions 29.9 and 29.10 of the Distribution Licence, or the storage business has GEMA's consent.

ER P2/6 Security of Supply and Interruptions Incentive Scheme

The substations which have been identified for the physical trials of the GBFM project are those that are closest to firm capacity. During the project we plan to operate the network within ER P2/6. However, it is possible that during the project an opportunity is identified to make use of a flexibility resource as an alternative to planned network reinforcement, for a substation that is forecast to exceed firm capacity in the near future.

The management of flexibility resources provided by customers connected to the distribution network is not a recognised technique under ER P2/6. In the event that we wish to take advantage of such an opportunity during the trial, and where the Methods are being rolled out after the trial, there is a risk that the relevant parts of the network could become non-compliant with ER P2/6. We would therefore seek a derogation from Standard Licence Condition 24.1(a) for the removal of the obligation to apply ER P2/6 for the affected Demand Group.

There is a risk that the use of flexibility resources to provide security of supply on selected parts of the network would result in delayed post fault restoration times which result in CI and CML penalties under the Interruption Incentive Scheme (IIS). In the event that we judge this risk to be material, we would seek an adjustment to the way CI and CML, which would be incurred in the relevant parts of the network, contribute to the IIS targets. We would achieve this by agreeing an amendment to the Ofgem document: "Electricity Distribution Price Control Customer Service Reporting - Regulatory Instructions and Guidance".

To the extent that such an application is successful, it would reduce the customer subsidy requirements of this project.

7: Regulatory issues contd.

ESQCR legislation

We have assessed whether the GBFM project is compliant with the ESQCR legislation. Since a discontinuation agreement is a prerequisite to interruptions under both Methods, we consider that the GBFM does not pose a compliance risk in relation to Regulations 23, 29 or 32 and that the project will be compliant with ESQCR legislation.

GB market arrangements

Our assessment suggests that the trials will not have an impact on GB electricity market arrangements. However, as set out in Section 4, during the project we intend to assess the implications that the roll out of both Methods would have for market arrangements, including the BSC.

7: Regulatory issues images, charts and tables

Regulatory issues images

Regulatory issues images

Section 8: Customer impacts

This section outlines the rationale for customer interactions during the trial, the types of interactions with customers, an assessment of potential customer interruptions and the steps taken to investigate alternative ways to implement the project which could have fewer impacts on customers.

8.1 The rationale for customer interactions

The project will trial sharing approaches for flexibility resources, that aim to increase the availability and reduce costs for GB DNOs. Because DSR is potentially one of the most important types of flexibility, interaction with customers, including interruptions, is required as part of the trial.

Interactions with customers are required to contribute to the Learning Outcomes of the project, most importantly to Learning Outcome 1. In particular, one of the key pieces of learning from the project will be to understand how much confidence the DNO can put in flexibility from DSR (and shared DSR) relative to other means of releasing capacity. It will not be possible to gain this learning without interacting with customers as part of the project.

8.2 Interactions with customers

There will be interactions with the following customer segments:

- industrial and commercial (I&C) customers participating through commercial aggregators or with Asda directly as a large energy user;
- non-domestic customers e.g. SME, government and corporate customers, aggregated by British Gas; and
- domestic customers including the tenants of Local Authorities and Housing Associations (LAHAs), aggregated by British Gas.

The project will target up to 20MW of DSR from the three generic customer segments outlined above. The exact composition of the portfolio will be developed during the project delivery phase. However, using experience from the CLNR project, Table 8.1 provides a clear indication of where the project is likely to be successful in delivering DSR for the GBFM. The British Gas aggregated portfolio of non-domestic and domestic customers will be targeted to deliver approximately 1MW of DSR for the GBFM. The balance will be sourced from I&C customers via the aggregators and Asda.

I&C customers

The project is collaborating with up to four commercial aggregators: Flexitricity, ESP, KiWi Power and EnerNOC. The aggregators have developed business models which can:

- identify customers with flexibility potential of value to the power industry;
- work with customers to develop the capability to provide flexibility;
- provide technical assistance with metering, equipment upgrades and communications;
- execute commercial agreements to monetise the arrangements; and
- implement operating procedures.

The project will work with the aggregators to engage with I&C half hourly customers that can offer flexibility either by load management or using on site generation. The project will target existing flexibility providers with experience of providing DSR, as well as customers new to these arrangements.

The requirements developed for the DNO, TSO and suppliers will be communicated to the customers via the aggregators, supported by the project as appropriate. The market design allows customers scope to offer flexibility based on their own individual capability, within the broad requirements of the DNO and other purchasers. The trials will use economic incentives for these aggregators and customers to provide flexibility, which are based on prices in existing flexibility frameworks such as STOR. The project will also engage with customers to develop their capabilities, where they are new to DSR arrangements.

Taken together, when engaging with commercial aggregators and customers providing flexibility through them, the project will build on the experience in the CLNR project to:

- develop aggregator and customer relationships;
- engage with appropriately located customers with a flexibility resource;
- develop commercial frameworks for providing this flexibility in the trials;
- implement operating procedures for the trials;

8: Customer impacts contd.

- use the DNO control systems and interfaces with aggregator control systems; and
- increase our knowledge of the security standards that can be applied to flexibility provided through aggregators.

The project will also work directly with Asda to gain an insight into flexibility provided by a large multi-site energy user. The role of the large energy user is the same as the aggregator role; the only difference is the large energy user has the internal energy management expertise to work directly with the industry rather than requiring an agent to support its participation.

British Gas, non-domestic and domestic customers

British Gas will engage with non-domestic (e.g. SME, government and corporate) customers; and domestic customers (either directly or in collaboration with LAHAs).

For all of British Gas's customers, interaction during the trials will include the following aspects:

- **Economic incentives.** There will be no change to how a customer is charged for the energy they use, so participants' bills will remain the same. The project will instead mimic a discount on energy bills by introducing a fixed participation incentive which customers will receive for offering DSR. These incentives may consist of a combination of vouchers and additional variable payments each time the resource is used.
- **Supply interruption.** Some demand resources will be called on to provide an actual response. This intervention will impact only on the energy use of specific appliances, such as smart wet goods or heat pumps. This will ensure that, by not affecting all of a customer's consumption, the overall impact on end users will be limited. In many cases, switching to thermal or electrical storage will remove any impact on a customer's comfort level. Many of the customers involved in the trial are likely to have previous experience of participating in DSR in this way (e.g. through night storage or the CLNR trial).
- **Customer engagement.** Given the importance of customers to this trial, there will be a considerable focus on customer engagement, communicating the concept of DSR, and understanding customer needs. This will build on the experience gained in the CLNR project, using British Gas's customer service resources. British Gas intends to engage customers using a process similar to that followed in the CLNR project, as outlined in Figure 8.1.

CLNR customers

British Gas engaged with more than 10,000 customers in Yorkshire and the North East during the CLNR project, and the GBFM project aims to re-engage some of these customers, particularly those with smart appliances and controllable heat pumps who may be most able to deliver flexibility. As a result of the CLNR project, these customers already have a high level of understanding of the energy system and the role of DSR. This provides a foundation for the GBFM trials to extend the engagement into the space of DSR providing flexibility services.

Using learning from CLNR and studies during the market evaluation, the most cost-effective means will be identified to consistently deliver around 1 MW of demand flexibility from the non-domestic and domestic sectors, the principal causes of winter peaks in the UK. The project will consider what is most cost-effective now and also what is most cost-effective in future scenarios to maximise the value of learning from GBFM.

Non-domestic customers (e.g. SME, government and corporate customers)- direct contact

The CLNR project is undertaking detailed monitoring of non-domestic customers to better understand energy use in different business types and sizes. This data will be used to identify the most appropriate participants for GBFM.

British Gas will try to identify customers with existing demand flexibility systems that can be aggregated via the service delivery platform (SDP). Installing new Building Management Systems would be very expensive. Instead, the project will seek out instances where there are some pre-existing building controls systems and endeavour to retrofit connectivity with the SDP. Ideally the first stage of the project will identify customers with some form of building management systems, micro-generation and storage, back-up generation, large scale lighting systems, or some other appropriate technologies. Commercial customers are an important sector for calls to increase demand, for instance in times of high wind output, heating, ventilation and air-conditioning controls will be a key technology to deliver increases on demand.

8: Customer impacts contd.

Where appropriate and cost-effective, the project will look to install microCHP or other low-carbon back-up generation and storage facilities to understand how technologies that will be more readily available in future scenarios will contribute to GBFM.

Domestic customers - direct contact

Controllable heat pumps, solar panels and storage and smart appliances

British Gas intends to re-engage customers from the CLNR project trial, bringing along some of the smart technology that can be used to provide DSR. By re-engaging with these customers, it is expected that a significant quantity of technologies will be contributed to the project.

For solar customers, "2nd life" EV batteries (or equivalent) will be installed to provide flexibility. These customers are proving to be some of the most engaged during the CLNR project so it would be beneficial to include them in GBFM as well.

Actual DSR calls for customers with heat pumps and thermal storage units will turn off heat pumps, leading the heating system to switch to stored heat energy. Impact on customers will be minimal as storage will be sufficient in most cases to maintain indoor temperatures. Customers will be made aware of the expected impacts in advance and will receive feedback throughout the trial; and will have the opportunity to leave the trial at any time if they feel the intervention is not sufficiently incentivised.

EV charge points

Smart EV charging points can control when the car is charged and collect data about charging. Slow EV take-up has limited these customers' involvement in the CLNR project and there is no guarantee that sales will increase within the timeframe required for GBFM. However, the project will endeavour to include at least one EV fleet, comprising five or more vehicles. It is hoped that the trial can include many more vehicles.

There has been increased interest in using EVs for corporate or LAHA fleets, due to government subsidies. Fleet vehicles are naturally used for shorter distances and often come back to a common location at multiple times throughout the day. British Gas is in discussions with a few fleet managers for a trial of charging management. If successful, we would like to include a similar proposition for using fleet charging management to deliver flexibility services within the GBFM trial.

Ideally, participating fleets would be located within the Northern Powergrid region, but if there is no interest locally, then we will look beyond the region to secure participation. EVs are likely to play a greater role in flexibility services in the 2030 time scale so it is important to try to involve at least one fleet.

Teleswitch storage heaters

Customers with Radio Teleswitch capability have electric storage heaters that can be remotely instructed to charge between specific times. Today this functionality is delivered via radio broadcasts, but this is being discontinued. For this project, these customers would receive a modern load-control device that allows dispatch of flexibility by their supplier. This functionality has not yet been tested, but this project will provide the opportunity.

Domestic customers - in collaboration with LAHAs

Localised concentrations of domestic flexibility resources will be tested in social housing, for example tower blocks with heat pumps and thermal storage. British Gas has developed a number of strong relationships with local authorities and housing associations in the Northeast and Yorkshire regions and would seek to continue involving them in the GBFM trial. By interacting with LAHAs, the project will be able to reach people impacted by fuel poverty and others that do not fall into the "early adopter" category. There is already strong support for the installation of low-carbon technologies and finding new ways to help their residents with their energy costs. As such, we would seek to set aside some funds dedicated to providing LAHAs with the technologies required to participate in the trial. As with the CLNR project, the project team would work closely with the LAHA to ensure customers are educated about the trial and the expected impacts.

The project team has already had successful conversations with some LAHAs to gauge interest in participation. For example, South Tyneside Homes manages 19,000 homes and is keen to explore the potential of advanced thermal storage to help reduce customer bills. Yorkshire Housing is looking to perform full energy retrofits on 20 tower blocks that currently use inefficient electric heating. Both of these projects would benefit from involvement with GBFM to further the business case for these energy management retrofits.

8: Customer impacts contd.

8.3 Number of interruptions

The number and pattern of interruptions faced by customers in the trials will be set according to the pattern and frequency of events likely to be called by the DNO and the number of calls required to allow robust results on responsiveness to be captured.

- **Pattern and frequency of events**. Northern Powergrid's requirements are for flexibility to be delivered over the four month winter period. Windows will be limited to four hour periods per day, to coincide with the peak periods on the distribution network. Northern Powergrid expects to call on 6% of customers to provide flexibility in any given year, with an average response required over ten working days for four hours on each day. For the trial, a response would be called from all participating customers. The exact pattern of calls will be established during the trial.
- **Robust results.** To deliver results at the required level of robustness the number of call-offs for each distinct type of resource should be at least 40 over the whole period of each trial. This number has been calculated as part of the initial trial design phase and may be revised during the project.

Alternative ways of running the project

The GBFM has been designed to include only interruptions to customers which are necessary to yield learning. Technology choice and target customers have been kept flexible to ensure the project uses the most cost-effective and realistic ways of delivering demand flexibility. We have limited the number of interruptions through the following:

- **Simulation.** Where possible, aspects of the trials will be simulated. These simulations will be used to test the market design before its deployment, and will also teach participants how to use the system. Simulation will reduce the reliance on customers delivering actual DSR, while also providing robust results. Simulation will be used to scale up the number of participants to investigate the effect of different numbers of purchasers and providers and test the effects of the conditions that are more likely in 2020 and 2030 on the market.
- **Robust sample size.** The trials have been designed to yield robust learning for both Methods at the Northern Powergrid scale, while minimising the number of customers that will actually have their supply disrupted. The participants were chosen to ensure that the project gained evidence on the key types of flexibility provider, while not involving more customers than necessary.
- **Applying Northern Powergrid's flexibility requirements.** The trials have been designed to capture the impact of providing flexibility at the times and frequencies that Northern Powergrid requires. This will limit the number of actual interruptions to customers' supply.

Customer Interruptions

The installation of network monitoring technology may result in both planned and or unplanned customer interruptions.

- **Planned interruptions.** A planned interruption may be required when the construction of the existing asset restricts safe, live working techniques or when enclosures need to be opened to gain access then it is necessary to protect our staff and the asset from damage.
- **Unplanned interruptions.** There is always a `risk of trip' when working on the equipment (e.g. when installing transformer temperature sensors or CT coils). The opportunities of a switched alternative may not be available while the installation or commissioning work is progressing. A risk assessment has concluded this risk can be minimised by using approved personnel, pre-approved practices and load switching.

We intend to install network monitoring devices at 15 primary substations. Three physical visits will be carried out at each site: 1) the site survey, 2) the installation and 3) the testing/commissioning of the devices. It is possible (though unlikely) that unplanned interruptions could be associated with these site visits. It is therefore prudent to assume that a maximum of 45 (3x15) unplanned interruptions could occur.

These events would probably last for around ten minutes, but could last for up to one day. The likely or most probable duration of an unplanned interruption is estimated at 10 minutes or less, typical causes would be disturbed connections of relays or associated panel works, or adjacent control panel works. It is considered possible that an unplanned interruption would last approximately one hour, typical causes could be a damaged or deteriorated wiring of control cables, connectors or transducers that require replacement and retest. Although considered improbable, the duration of an unplanned interruption could extend to one day, typical causes include faulting components, fire, irreparable damage requiring equipment replacement and re-commissioning.

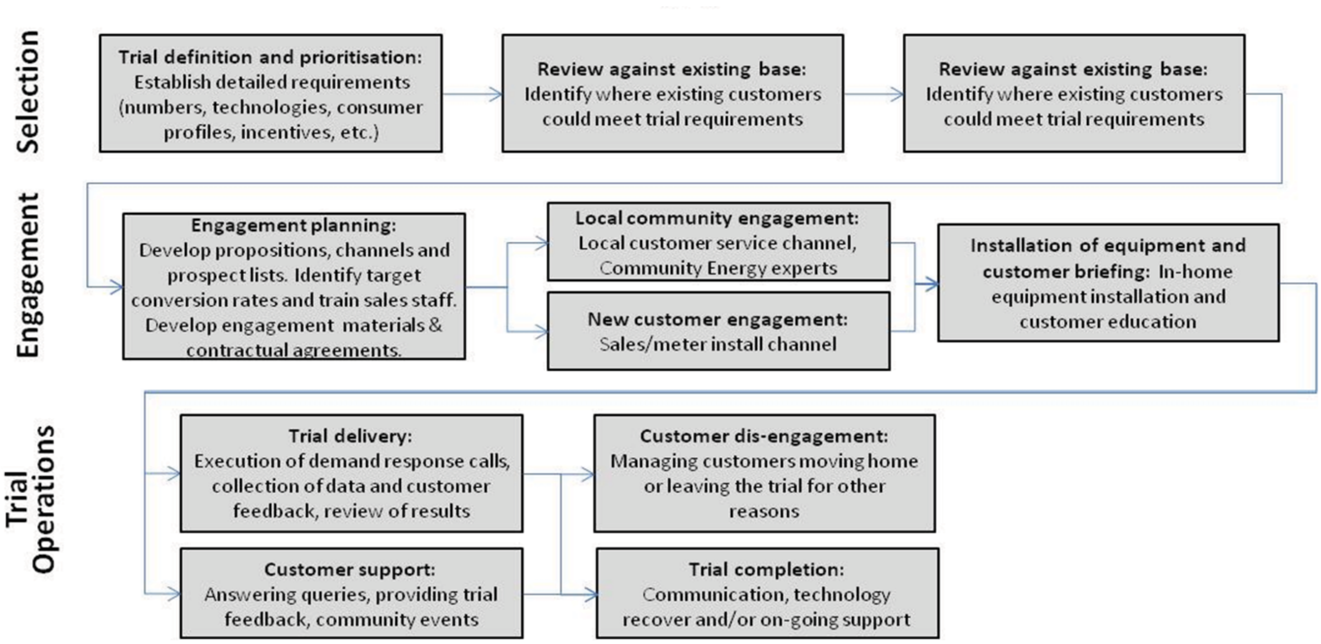
8: Customer impacts images, charts and tables

Table 8.1 Summary of the customer target plan

Customer Segment	Customer engagement channel	Customer Type	Projected customer numbers (note 1)	DSR volumes (MW)
Industrial and commercial	Commercial aggregators & Asda	Load management		19
		Generation (e.g. CHP, diesel)		
Non-domestic (SME / Corporate Customers)	British Gas direct customer contact	Building management systems	10	1
		Micro-generation and storage	10	
		Other suitable technologies - lighting systems, refrigeration	10	
Domestic	British Gas direct customer contact	Controllable heat pumps	50	
		Smart appliances	50	
		Solar panels and storage	75	
		EV charge points	15	
		Teleswitch storage heaters	400	
	British Gas via LAHA	Thermal Storage, heat pumps etc.	5 LAHAs	
			Total portfolio	**20**

Note 1 – The scale of the customer DSR portfolio is targeted at 20MW. The I&C segment will deliver the majority of the DSR requirement for the GBFM. However, the smaller non-domestic and domestic customers are targeted to deliver a minimum of 1MW of DSR; the exact composition of customer types will be determined following the findings from the CLNR project and the most cost effective options determined during the market study phase of the project. The Project considers that it is realistic to source 1MW of DSR from the non-domestic and domestic customers.

Figure 8.1 The customer engagement process



Section 9: Succesful Delivery Reward Criteria

Criterion (9.1)

Produce robust recommendations on measures required for DNOs to make use of demand side response (DSR) based on robust trialling of the Methods.

Evidence (9.1)

- Initial customer engagement plan submitted for approval by Ofgem in July 2013 for the DNO-TSO trials and September 2013 for the multi-party trials.
- Initial customer recruitment for the network operator trials completed by December 2013 and for multi-party trial by November 2014.
- Analysis of results of customer engagement and participation produced by December 2016.
- Report setting out the contribution DSR can make to DNOs and recommendations on measures required to allow DNOs to make use of DSR produced by December 2016.

Criterion (9.2)

Produce recommendations on measures required for DNOs to trade and share DNO-storage based on robust trialling of the Methods.

Evidence (9.2)

- Trial design document on electrical energy storage (EES) element of trial for robust results produced by February 2014.
- Technical requirements for EES to participate in trials specified by December 2013.
- Analysis of results of the trials relating to storage produced by December 2016.
- Report setting out the contribution storage can make to DNOs and recommendations on measures required to allow DNOs to trade and share storage produced by December 2016.

9: Succesful delivery reward criteria contd.

Criterion (9.3)

Ensure technology is in place to allow the project to access flexibility which will demonstrate robust and applicable trialling of each Method.

Evidence (9.3)

• Monitoring equipment in place by start of trials: December 2013 for the DNO-TSO trials and November 2014 for the multi-party trials.
• British Gas technologies for the trial in place by November 2014.
• Platform commissioned by October 2014.

Criterion (9.4)

• Design and undertake robust network operator (DNO-TSO) trial, analyse the results and produce recommendations.

Evidence (9.4)

• Run a working group for market participants and core stakeholders to inform the development of new commercial arrangements by December 2013.
• Trial design document produced by October 2013.
• Operating procedures and commercial frameworks for the trial produced by December 2013.
• Trial undertaken December 2013-June 2014.
• Assessment of trial produced by December 2014.

9: Succesful delivery reward criteria contd.

Criterion (9.5)

Design and undertake robust multi-party trial, analyse the results and produce recommendations.

Evidence (9.5)

• Implement an industry-wide engagement process to inform the design process of Method 2, offer the opportunity to monitor the trials and to contribute to the findings from the trials by July 2016.
• Evidence to inform whether or not to proceed with the multi-party trial produced by October 2013.
• Results of the techno-economic modelling to inform multi-party trial design produced by May 2014.
• Results of social research to inform the design of the multi-party market produced by May 2014.
• Market design document produced by May 2014.
• Trial design document produced by September 2014.
• Prototype market trading platform delivered by the end of November 2014.
• Multi-party trials undertaken from winter 2014/15 to winter 2015/16.
• Assessment of trials produced by December 2016.

Criterion (9.6)

Produce recommendations and roadmaps which set out how the Methods could best be applied to all DNOs, and communicate this learning.

Evidence (9.6)

• Implement an industry-wide consultation process to inform the recommendation and roadmap for the two methods by December 2016.
• Engineering guidelines and codes of practice for use of flexibility by a DNO produced by December 2016.
• Six-monthly progress reports submitted to Ofgem throughout the Project.
• Economic, social and technical evaluation of both Methods produced by December 2016.
• Close down report submitted to Ofgem in December 2016.
• Roadmap for network operator trilateral contracts by January 2015.
• Roadmap for multi-party market by December 2016.

9: Succesful delivery reward criteria contd.

Criterion (9.7)

Ensure a plan has been created which enables the project to deliver the key project milestones and outputs.

Evidence (9.7)

- Project structure populated with named resources issued by July 2013.
- Project management methodology description, project governance framework and detailed project plan issued by July 2013.

Criterion (9.8)

Evidence (9.8)

Section 10: List of Appendices

1. Full submission spreadsheet
2. Maps and network diagrams
3. Project plan, risk register, contingency plan and organogram
4. Project partners
5. Base case costs and comparison of Method and project costs
6. Proposed GBFM market design
7. Trial design
8. Market modelling for the GBFM
9. Transfer into business as usual
10. International review
11. Potential collaboration with UK Power Networks

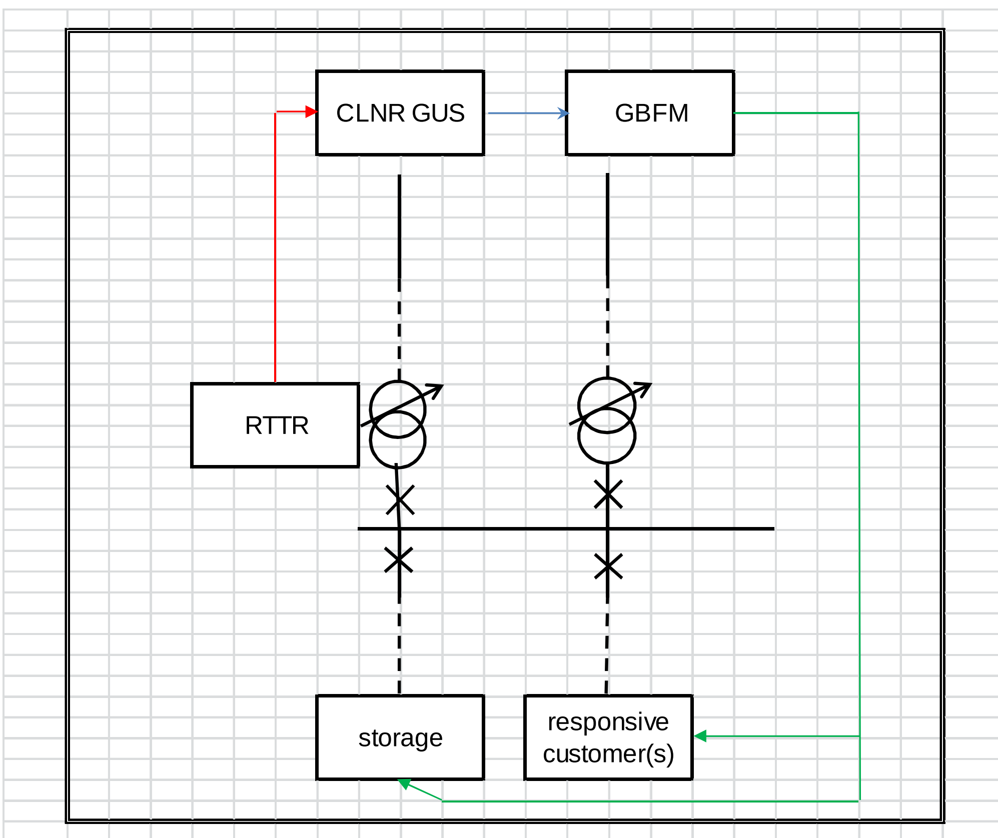
Mandatory Appendices
Appendix 2: Maps and network diagrams

The network technology aspect of the GBFM project will build on the outputs from the CLNR project. The CLNR project is:

- installing monitoring equipment to create a dynamic view of the rating (maximum current-carrying capacity) of selected, sensitive assets;
- creating control loops within the power flow management system named the Grand Unified Scheme (GUS) so that when thermal limits are being approached, a call is generated for DSR, to reduce power flows so that thermal limits are not exceeded;
- developing interfaces to DSR providers, to propagate the call for DSR; and
- simulating the credible worst cases against which DSR is our insurance, artificially modifying parameters in the monitoring system to make assets appear overloaded when they are not.

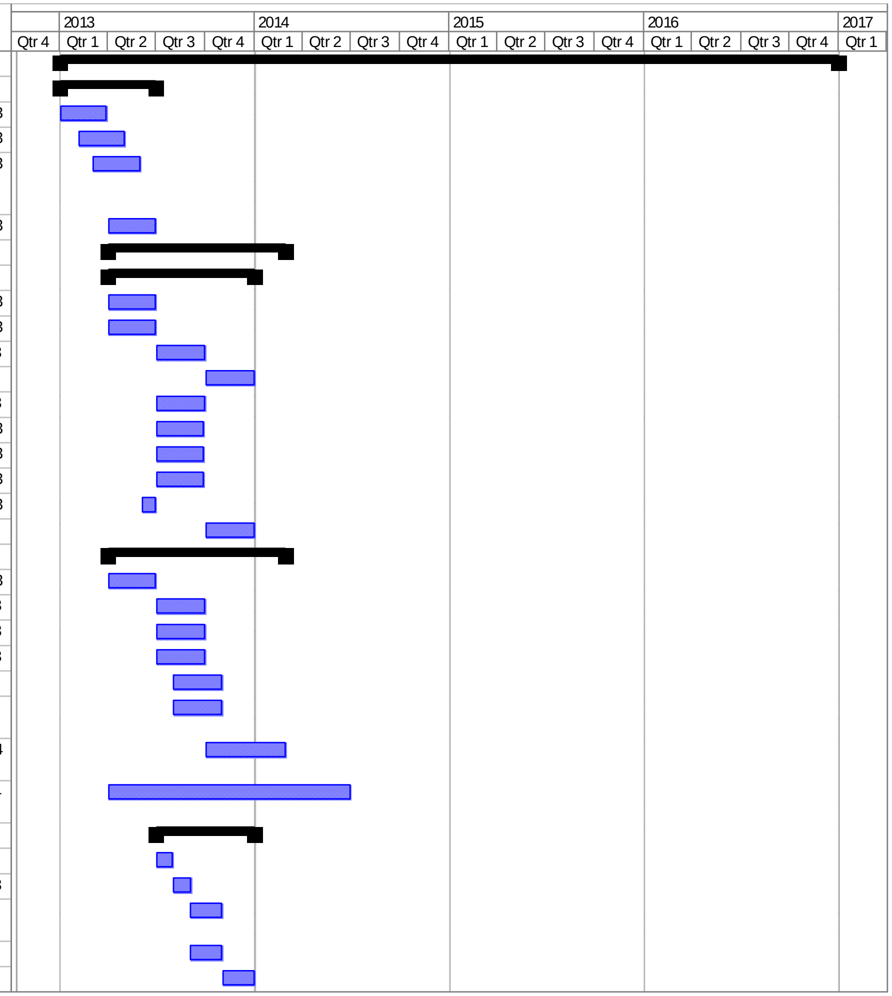
The network technology implementation for the GBFM is illustrated in Figure A2.1. There will be no change to the business processes developed in CLNR, nor in the GUS user interface. There will be a need for another interface from GUS to GBFM and there will be additional monitoring and controlling hardware installed at up to a further 15 sites, which the modular design of GUS facilitates.

Figure A2.1: Network diagram

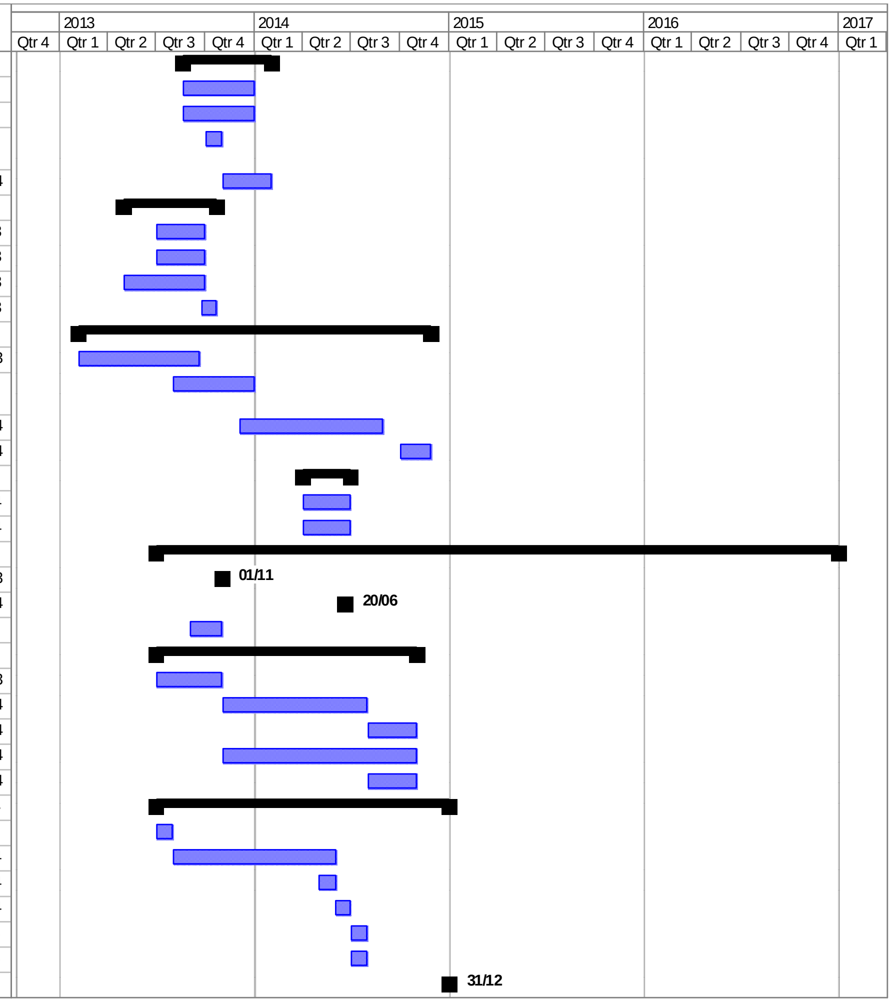


Appendix 3: Project plan, risk register, contingency plan and organogram

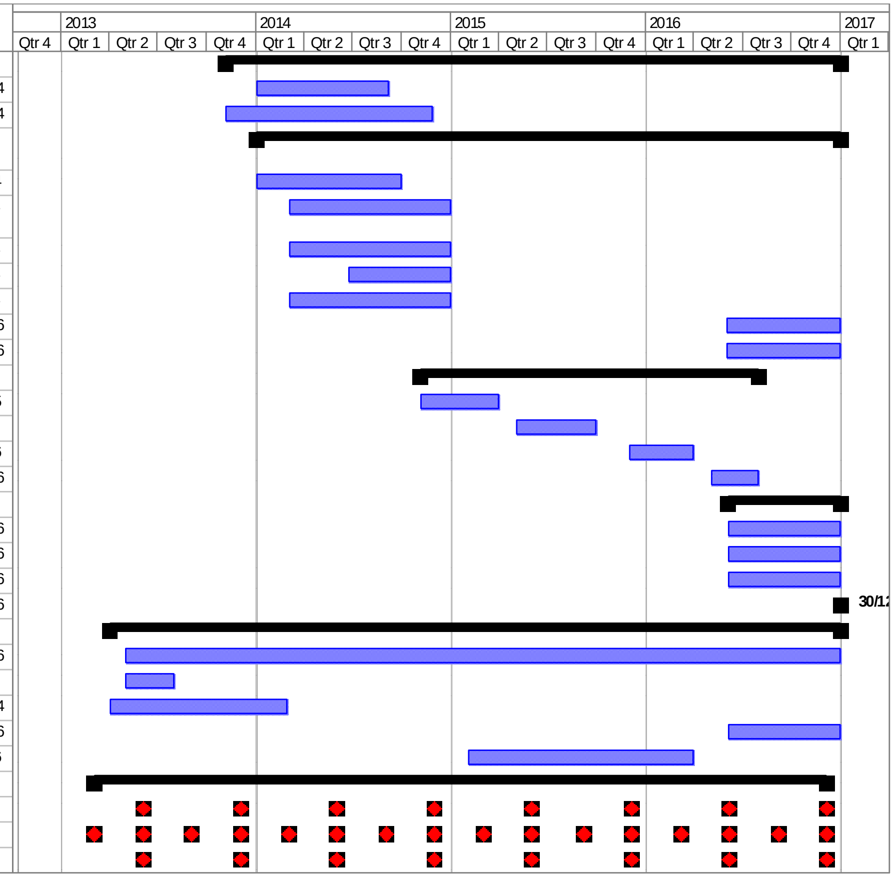
ID	Task Name	Start	Finish
1	**GBFM Project**	**Tue 01/01/13**	**Fri 30/12/16**
2	**Project Readiness**	**Tue 01/01/13**	**Fri 28/06/13**
3	Assign Resources	Tue 01/01/13	Fri 29/03/13
4	Project Management Methodology	Mon 04/02/13	Fri 03/05/13
5	Project Governance (delegated responsibilities, decision process, risk management etc)	Mon 04/03/13	Fri 31/05/13
6	Detailed project planning	Mon 01/04/13	Fri 28/06/13
7	**Stage 1 : Desktop Assessment**	**Mon 01/04/13**	**Fri 28/02/14**
8	**Market participants requirements**	**Mon 01/04/13**	**Tue 31/12/13**
9	DNO network requirements workshops	Mon 01/04/13	Fri 28/06/13
10	TSO workshops	Mon 01/04/13	Fri 28/06/13
11	Supplier, generator and energy trader workshops	Mon 01/07/13	Mon 30/09/13
12	BG - Customer technology and flexibility assessment	Tue 01/10/13	Tue 31/12/13
13	Aggregator workshops	Mon 01/07/13	Mon 30/09/13
14	Major Energy User workshops	Mon 01/07/13	Fri 27/09/13
15	End User workshops (LAHAs, SMEs, etc)	Mon 01/07/13	Fri 27/09/13
16	Other core stakeholders workshops (govt & reg bodies, acade	Mon 01/07/13	Fri 27/09/13
17	TSO / DNO workshops	Mon 03/06/13	Fri 28/06/13
18	Consolidated multi-party workshops	Tue 01/10/13	Tue 31/12/13
19	**EES Assessment**	**Mon 01/04/13**	**Fri 28/02/14**
20	Flexibility assessment of the asset	Mon 01/04/13	Fri 28/06/13
21	Current market channel assessment across the value chain	Mon 01/07/13	Mon 30/09/13
22	Business Case evaluation for EES in the current environment	Mon 01/07/13	Mon 30/09/13
23	Recommendations (Regulatory & Commercial)	Mon 01/07/13	Mon 30/09/13
24	Flexibility assessment for the GBFM	Thu 01/08/13	Thu 31/10/13
25	Design operating procedures for the DNO/TSO trial & multi-Party Trials	Thu 01/08/13	Thu 31/10/13
26	Produce implementation plan for BAU operational delivery	Tue 01/10/13	Fri 28/02/14
27	Network Technology - Assessment, Installation & Commissioning	Mon 01/04/13	Mon 30/06/14
28	**TSO / DNO Operating & Commercial frameworks**	**Mon 01/07/13**	**Tue 31/12/13**
29	Document participants requirements	Mon 01/07/13	Wed 31/07/13
30	Design resourcing sharing procedures	Thu 01/08/13	Mon 02/09/13
31	Design operating frameworks (e.g. dispatch, information flows, validation, settlement)	Mon 02/09/13	Thu 31/10/13
32	Produce commercial frameworks	Mon 02/09/13	Thu 31/10/13
33	Test assumptions and operating frameworks with resource provide	Fri 01/11/13	Tue 31/12/13



ID	Task Name	Start	Finish
34	**Multi-Party Market Design**	**Mon 19/08/13**	**Fri 31/01/14**
35	Document participants requirements	Mon 19/08/13	Tue 31/12/13
36	Produce market design options	Mon 19/08/13	Tue 31/12/13
37	Test assumptions and operating frameworks with resource providers	Tue 01/10/13	Thu 31/10/13
38	Finalise Market Design	Fri 01/11/13	Fri 31/01/14
39	**Market Analysis**	**Wed 01/05/13**	**Mon 21/10/13**
40	Macro Costs / Benefits (£, Carbon, liquidity)	Mon 01/07/13	Mon 30/09/13
41	Test project applicability at the national level	Mon 01/07/13	Mon 30/09/13
42	Techno-Economic model	Wed 01/05/13	Mon 30/09/13
43	Stage 3 : Go - No Go report	Mon 23/09/13	Mon 21/10/13
44	**Stage 2 : TSO-DNO Trials**	**Mon 04/02/13**	**Fri 28/11/14**
45	Trial Design	Mon 04/02/13	Fri 20/09/13
46	Flexibility resource acquisition process (customers, EES, generation etc)	Thu 01/08/13	Tue 31/12/13
47	Trials	Mon 02/12/13	Fri 29/08/14
48	Stakeholder workgroup review	Wed 01/10/14	Fri 28/11/14
49	**Capture Learning**	**Tue 01/04/14**	**Mon 30/06/14**
50	Learning outputs to inform the multi-party trials	Tue 01/04/14	Mon 30/06/14
51	Learning outputs to inform BAU roll-out	Tue 01/04/14	Mon 30/06/14
52	**Stage 3 : Multi-Party Market**	**Mon 01/07/13**	**Fri 30/12/16**
53	Project Go - No Go Decision point	Fri 01/11/13	Fri 01/11/13
54	Partner Go - No Go Decision point	Fri 20/06/14	Fri 20/06/14
55	Stakeholder workgroup review	Mon 02/09/13	Thu 31/10/13
56	**Supplier VPP Platform Development**	**Mon 01/07/13**	**Fri 31/10/14**
57	Assessment of requirements	Mon 01/07/13	Fri 01/11/13
58	VPP development	Fri 01/11/13	Fri 01/08/14
59	VPP Commissioning	Fri 01/08/14	Fri 31/10/14
60	Integration of 3rd party control systems	Fri 01/11/13	Fri 31/10/14
61	Integration with Service Delivery Platform	Fri 01/08/14	Fri 31/10/14
62	**Market Platform Delivery**	**Mon 01/07/13**	**Wed 31/12/14**
63	Short list preferred suppliers	Mon 01/07/13	Wed 31/07/13
64	Platform Development	Thu 01/08/13	Mon 02/06/14
65	Produce ITT for the market platform	Thu 01/05/14	Mon 02/06/14
66	Issue ITT	Mon 02/06/14	Mon 30/06/14
67	ITT response from suppliers	Tue 01/07/14	Thu 31/07/14
68	ITT assessment, interviews, finalisation	Tue 01/07/14	Thu 31/07/14
69	Platform Delivery	Wed 31/12/14	Wed 31/12/14



ID	Task Name	Start	Finish
70	**Multi-Party Trials**	**Mon 04/11/13**	**Fri 30/12/16**
71	Trial Design	Wed 01/01/14	Fri 05/09/14
72	Customer Acquisition Process	Mon 04/11/13	Fri 28/11/14
73	**Domestic / SME flexibility installation / decommissioning**	**Wed 01/01/14**	**Fri 30/12/16**
74	Collect average baseline data with SM	Wed 01/01/14	Tue 30/09/14
75	Flexibility Technology installed at customer premises	Mon 03/03/14	Wed 31/12/14
76	Smart meter and hub installation	Mon 03/03/14	Wed 31/12/14
77	Personal baseline data collection using SM	Mon 23/06/14	Wed 31/12/14
78	Modify CLNR technology - controls etc	Mon 03/03/14	Wed 31/12/14
79	Decommissioning	Wed 01/06/16	Fri 30/12/16
80	End Use Wrap-Up and Dissemination	Wed 01/06/16	Fri 30/12/16
81	**Multi-Party Trials**	**Mon 03/11/14**	**Fri 29/07/16**
82	Winter 15	Mon 03/11/14	Tue 31/03/15
83	Summer 15	Mon 04/05/15	Wed 30/09/15
84	Winter 15 / 16	Tue 01/12/15	Thu 31/03/16
85	Stakeholder workgroup review	Mon 02/05/16	Fri 29/07/16
86	**Learning Outputs**	**Thu 02/06/16**	**Fri 30/12/16**
87	GBFM Evaluation including stakeholder reviews	Thu 02/06/16	Fri 30/12/16
88	National recommendation	Thu 02/06/16	Fri 30/12/16
89	National implementation roadmap	Thu 02/06/16	Fri 30/12/16
90	Project close down report	Fri 30/12/16	Fri 30/12/16
91	**Stakeholder Engagement**	**Mon 01/04/13**	**Fri 30/12/16**
92	PR campaign	Wed 01/05/13	Fri 30/12/16
93	Roadshows	Wed 01/05/13	Wed 31/07/13
94	Market design and initial evaluation consultation	Mon 01/04/13	Fri 28/02/14
95	Final evaluation, recommendations and roadmaps consultation	Thu 02/06/16	Fri 30/12/16
96	Trial observation opportunities (Method 2)	Mon 02/02/15	Thu 31/03/16
97	**Project Governance & Reporting**	**Mon 04/03/13**	**Mon 05/12/16**
98	**Project review reports (six-monthly)**	**Mon 03/06/13**	**Mon 05/12/16**
107	**Steering Group Meetings**	**Mon 04/03/13**	**Mon 05/12/16**
124	**Exec Sponsor Group Meetings**	**Mon 03/06/13**	**Mon 05/12/16**



Risk Register

No	Description	Prob.	Impact	Mitigation
Project management risks				
1	Key personnel not available to deliver the project	Low	High	• Identify resource requirements during Q312 and Q412 in readiness for the project initiation • Ensure individuals share and document knowledge
2	Poor project management threatens the learning outcomes and/or results in cost and time overruns	Low	High	• Leverage learning from the CLNR project to implement robust governance frameworks • Appoint skilled project management resources
3	Project partners and/or collaboration partners are no longer willing or able to support the project	Low	High	• Ensure Memorandum of Understanding agreements are in place • Partner with organisations participating in the CLNR project or with highly regarded organisations • Ensure that if Elexon's vires are not extended, the project can still go ahead
Technology and systems risks				
4	The costs of delivering the GBFM platform are higher than expected or delivery takes longer than expected	Low	High	• Implemented a RFI process during summer 2012 to minimise delivery uncertainty • Select a systems provider through a rigorous assessment process ensuring the project's requirements are accurately specified
5	The costs of developing this technology commissioned as part of the CLNR project (e.g. GBFM / GUS interface, network monitoring and the British Gas aggregation platform) are higher than expected or that delivery will take longer than expected	Low	High	• Leverage the experience gained from the CLNR project to minimise this risk
6	Expected technology for providing, managing and monitoring demand flexibility is not available in time for the trial	Low	Medium	• We have not fixed on specific technologies to deliver the DSR resource • Holding conversations with a range of technology providers

No	Description	Prob.	Impact	Mitigation
7	CLNR fails to deliver required network technology in time for the project	Low	Medium	• Include simulation as part of the project to ensure specific gaps can be filled if required • Restructure the project and potentially defer some activities to the multi-party trials
8	Market design is not compatible with existing markets	Low	High	• Market design workstream led by Elexon, experts in existing market frameworks • Detailed review of all design options by partners, including National Grid
Flexibility provider risk				
9	Not enough participants can be encouraged to join the trials to allow for a robust evaluation of the results	Medium	Medium	• Involve experienced partners • Review legal, commercial, technical and social barriers to participation prior to the trials • Use CLNR participants where possible, many of whom already have required technologies • Deliver workshops to involve participants in design • Assist partners in forming their resource profiles for each time-frame of interest • Involve aggregators and Asda • Use experience from the CLNR project e.g. the experience gained from the social science customer engagement processes
10	Not enough participants in the right locations can be recruited to the trials	High	Low	• Broaden the geographic search for customers • Simulate the exact location of participants on the network
11	Providers of flexibility recruited to the trial do not respond to market signals	Medium	Negligible	• Signals set to rates that are likely to be commercially viable in the near term, 2020 and 2030 • If participants do not respond to economic signals in the trial, this will provide learning itself
12	There is not enough flexibility available for a liquid market	Medium	Negligible	• Market will be populated by simulated participants up to the levels expected in the near term, 2020 and 2030 • Measures of liquidity will be a key output of the trial and can be studied using the market model and simulation

No	Description	Prob.	Impact	Mitigation
13	Storage cannot participate effectively in the market – for technical or cost reasons	Medium	Negligible	• Use of storage being purchased for CLNR to minimise the costs of this part of the trial • Potentially investigate opportunities to collaborate with UKPN
14	Subsidy requirements for providers of flexibility are higher than expected	Low	High	• Subsidy requirements have been based on current market rates for National Grid products with a high level target applied to the benefits associated with sharing this resource
DSR buyer risk				
15	Little or no flexibility is required by market participants during the trial	Negligible	Low	• Simulate events requiring flexibility
16	The DNO need for flexibility reduces, so that this project is no longer required	Negligible	High	• Update Northern Powergrid needs for reinforcement at the start of the project • Assess DNO needs for flexibility as part of setting the purchase requirements for the timeframes of interest
Learning & Dissemination				
17	Results are not statistically significant	Medium	Low	• Trial design by EA Technology and peer review by Durham University to ensure statistical significance is maximised • Use of complementary data from other trials to increase sample numbers • Use of data on reliability from other markets (e.g. STOR) • Qualitative analysis where certain customer types are too rare to ensure statistical significance (e.g. EV owners)
18	Results are not applicable to DNOs across GB	Low	High	• Undertake upfront analysis on the potential for replication • Deploy model-based simulation to allow the model to be re-run under different conditions to those actually experienced in the trial periods • Ongoing engagement with all DNOs to ensure GBFM's wider relevance

No	Description	Prob.	Impact	Mitigation
19	Project learning is not captured by partners	Medium	Medium	• Include sufficient time in each project partner's plan to capture learning • Durham University will be supporting the project to capture learning robustly

Contingency plan

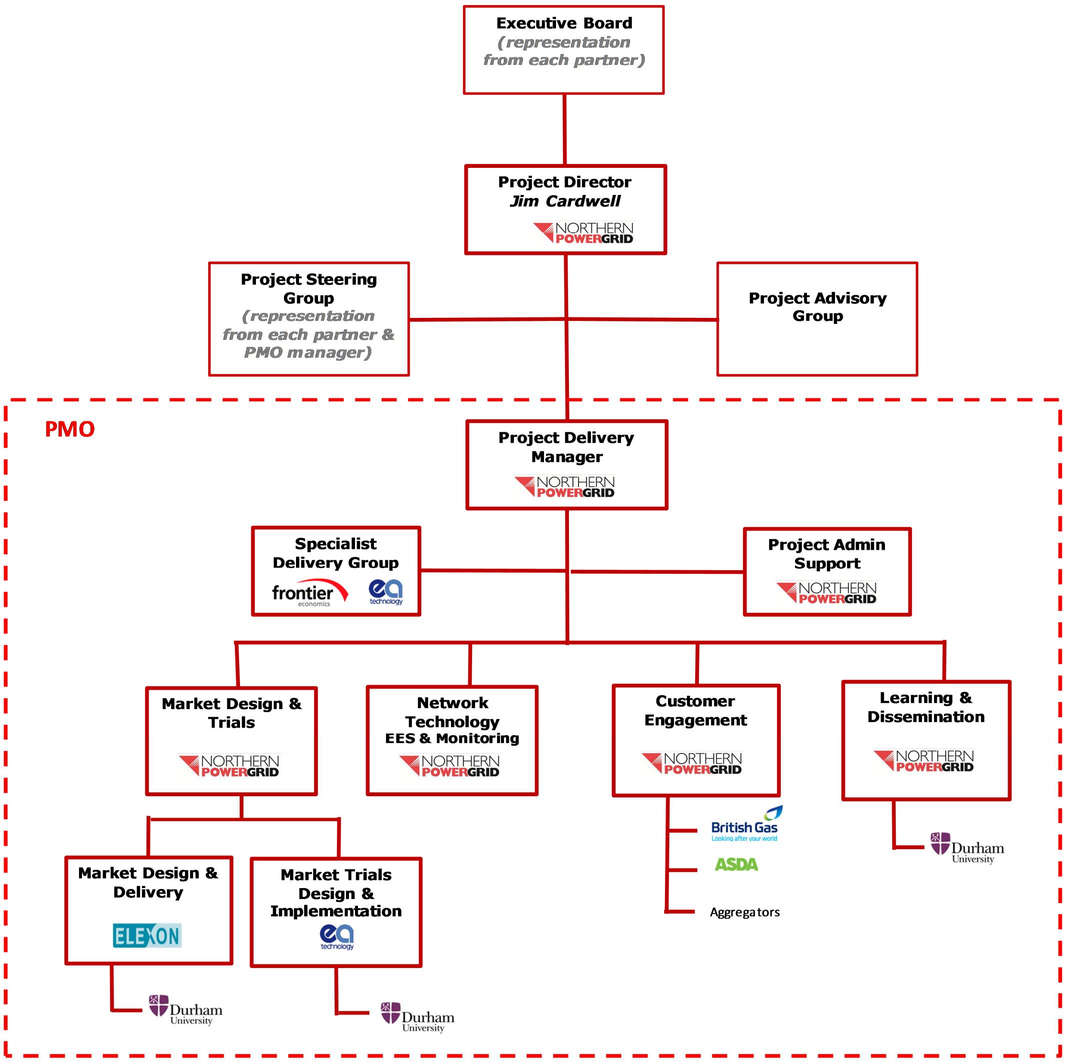
Contingency planning is not a stand-alone workstream in the project, but is a central feature of the project governance framework described in Section 6 (project readiness).

The objective of the project governance framework is to clearly communicate the project vision to all participants, identify relevant and timely project milestones and deliver these through robust planning and timely and effective decision making, resolution of issues, control of changes, mitigation of risks and contingency planning.

The project has the advantage of building on the working relationships developed during the CLNR project, which reduces the project management and delivery risks associated with multi-partner projects.

The GBFM project requires the CLNR project to deliver a number of outputs, most notably from the delivery of the EES, network monitoring, network control systems and customer behaviour and requirements insights. There is overlap between the two projects within Northern Powergrid which will ensure that the GBFM project is kept aware of developments within the CLNR project.

Organogram



Roles

Project director

The project director has ultimate responsibility for project direction.

Project steering group

The project steering group will be represented by each project partner. The steering group will support the project director with the authorisation of key decisions.

Project advisory group

The project advisory group will meet twice every year and will provide an independent expert sounding board for the project. The board will take representation from industry experts (e.g. Sustainability First), other trials (e.g. Twenties) and colleagues from the project partners not directly responsible for delivery.

Executive board

The project director will report to the executive board. The executive board will be represented by a senior manager in each partner organisation and the President & Chief Executive Officer of Northern Powergrid.

Project management office (PMO)

The PMO is responsible for delivering the project. Northern Powergrid will provide the resource for this role.

The PMO workstreams are led by the partners with the main responsibility for project delivery in that area. Each workstream therefore has two generic responsibilities:

- project delivery; and
- project management obligations.

The PMO team will meet regularly at various locations to discharge their project management responsibilities; as specified during the project mobilisation phase.

Workstreams

For each of the four workstreams, we now set out the lead, and describe the key deliverables, responsibilities and consulted parties.

Workstream 1: Market design, delivery and trials

Northern Powergrid has lead accountability and responsibility for this workstream. This workstream is divided into two sub-workstreams:

- Workstream 1a: Market design and delivery; and
- Workstream 1b: Market trials design and implementation.

Workstream 1a: Market Design & Delivery

Elexon has lead responsibility and accountability for this workstream and is responsible for two principal deliverables:

- production of the market design document; and
- delivery of the multi-party trading platform and user training.

Durham University (social science) will advise on the design of the commercial arrangements being trialled, ensuring that lessons learned from the CLNR and from international experience are incorporated.

All project partners and collaborators will be consulted during this workstream. The consulted parties are responsible for:

- supporting the Elexon process to gather information on requirements;
- providing their GBFM requirements to Elexon;
- providing input to the market design;
- reviewing and supporting the Elexon process to finalise the market design documentation and Invitation to Tender documentation;
- participating in the user acceptance testing and training processes implemented by Elexon; and
- providing outputs to the learning and dissemination workstream.

Workstream 1b: Market trials design and implementation

Northern Powergrid has lead accountability for this workstream and EA Technology has lead responsibility.

EA Technology is responsible for:

- designing the network operator trial;

- designing the multi-party trial;
- producing trial plans for both trial types;
- allocation and rationale of trial plans split between real and simulated events;
- coordinating the trials;
- technical analysis of the results of the trials; and
- providing outputs to the learning & dissemination workstream.

Durham University is responsible for:

- peer review of the design of the trials;
- peer review of the techno-economic market model;
- leading on the statistical investigation of variability and associated confidence levels pertaining to the outputs of the trials;
- using the existing Smart Grids simulation and emulation laboratory at Durham University to test the GBFM where real trials prove impractical;
- reviewing the technical analysis of the results of the trials; and
- providing outputs to the learning & dissemination workstream.

Northern Powergrid and National Grid are responsible for:

- designing resource sharing procedures for the network operator trials;
- designing operating frameworks for the network operator trials;
- producing new commercial frameworks to take to market for the network operator trials;
- acquiring DSR customers that can provide flexibility;
- participating in the trials; and
- providing outputs to the learning & dissemination workstream.

All project partners and collaborators will be consulted during this workstream. The consulted parties are responsible for:

- reviewing and signing off trial plans ensuring the Methods are being fully tested, based on each participant’s requirements;
- development of the scenarios (e.g. covering 2020, 2030, and higher levels of participation) that should be run through the simulation; and
- contributing to the development of resource sharing procedures, operating frameworks and new commercial frameworks for the network operator trials.

Workstream 2: Customer engagement

Northern Powergrid has lead accountability for this workstream with lead responsibilities with British Gas, Asda and the aggregators.

British Gas is responsible for:

- developing a VPP-style platform to aggregate and measure DSR from domestic and non-domestic customers;
- employing smart meters to help measure responses to DSR calls;
- attracting customers to the project within the two target areas that can deliver DSR;

- installing or leveraging CLNR installed customer technology to facilitate DSR by domestic and non-domestic customers; and
- providing outputs to the learning and dissemination workstream.

Asda is responsible for offering DSR flexibility from its existing sites located in the two target regions.

The aggregators are responsible for offering DSR flexibility from their existing I&C portfolios and/or acquiring new I&C DSR customers capable of participating in the trials.

British Gas, Asda and the aggregators are responsible for supporting the demand side learning from the trial.

All project partners and collaborators will be consulted in this workstream. The consulted parties are responsible for reviewing the GBFM customer resource capabilities to benchmark against their flexibility requirements.

Workstream 3: Network technology

Northern Powergrid has lead accountability and responsibility for this workstream.

For EES, Northern Powergrid will be responsible for:

- assessing the physical flexibility the EES asset can offer;
- assessing the current market options available to maximise revenues for these assets and updating the business case for EES;
- recommending regulatory and commercial changes to the current market frameworks which would improve the business case for deployment of these assets;
- designing operating procedures for the assets relevant for participation in the network operator and multi-party trials;
- engaging in the network operator and multi-party trials;
- providing outputs to the learning and dissemination workstream; and
- producing a road map for business as usual operations.

For network monitoring, Northern Powergrid will be responsible for:

- installing monitoring and communication devices on 15 primaries;
- creating an interface from GUS to the market platform;
- designing operating procedures and implementing the procedures for the trials;
- providing outputs to the learning and dissemination workstream; and
- producing a road map for business as usual operations.

National Grid, Elexon, Frontier Economics and EA Technology will be consulted. The consulted parties are responsible for supporting Northern Powergrid with the outputs. In particular, Frontier Economics will produce the updated business case and EA Technology will produce the physical flexibility assessment, operating procedures and BAU road map.

Workstream 4: Learning and dissemination

Northern Powergrid has lead accountability and responsibility for this workstream. The key deliverables and responsibilities are as follows:

- Northern Powergrid is responsible for delivering the learning and dissemination plan;

- EA Technology and Durham University are responsible for delivering the analysis of the results of the trial;
- Northern Powergrid is responsible for delivering the social science evaluation of the trial – in particular, for investigating the institutional barriers to new commercial arrangements, and how they might be overcome;
- Frontier Economics is responsible for assessing the economic net benefits of the Methods and for formulating the recommendations for a national implementation plan, supported by Elexon; and
- EA Technology is responsible for delivering the technical element of the techno-economic model.

Each partner has a responsibility to support the learning and dissemination workstream. While Northern Powergrid will lead this workstream, the outputs will require contributions from each project partner and collaborator.

Appendix 4: Project partners

Project partners					
Project partner	**Organisation description**	**Project role**	**Funding provided**	**Contractual relationship**	**Partner benefits**
British Gas	Largest energy supplier in the UK and will leverage the expertise developed during the CLNR project	Customer engagement to deliver flexibility services to the GBFM primarily with commercial, SME and domestic customers	Yes Smart meters, customer relationships developed during CLNR, customer technology (heat pumps) and an aggregation platform	CLNR collaboration agreement Signed a Memorandum of Understanding	Enhanced understanding of how customers can support the transition to a low-carbon economy. Development of a coordinated and transparent flexibility market
Centrica Energy	Energy trading and optimisation expertise	A purchaser of flexibility from the GBFM to optimise imbalance positions	None	Signed a Memorandum of Understanding	Development of a coordinated and transparent flexibility market Enhanced understanding of how to minimise costs in a low-carbon economy

Project partners					
Project partner	**Organisation description**	**Project role**	**Funding provided**	**Contractual relationship**	**Partner benefits**
National Grid	Owns the electricity transmission network in England and Wales and operates the entire transmission system throughout Great Britain	A purchaser of flexibility to manage the national transmission network	Providing expert input to the development of each Method at no charge	Signed a Memorandum of Understanding	Development of a coordinated and transparent flexibility market Potential to reduce the costs associated with managing the transmission network
Elexon	Implemented and developed one of Great Britain's largest energy industry codes, and continues to handle its day-to-day governance	Market Design, market procurement and implementation process and market operator role	None	Signed a Memorandum of Understanding	Support with assessing existing industry code issues associated with flexibility services Leverage core capabilities to further develop industry processes that solve industry issues

Project partners					
Project partner	**Organisation description**	**Project role**	**Funding provided**	**Contractual relationship**	**Partner benefits**
Durham University	Internationally recognised leading researchers providing engineering and social science support to the project	Engineering, statistics and social science research, peer review and modelling and simulation	None	CLNR collaboration agreement Signed a Memorandum of Understanding	Opportunity to apply expertise to solve industry issues
EA Technology	Extensive knowledge of electricity, utilities, infrastructure and associated sectors and will provide engineering input to the project	Trial design and specialist project support across workstreams	EA Technology is providing a contribution to the project through a discount in fee rates	CLNR collaboration agreement Signed a Memorandum of Understanding	Opportunity to apply expertise to solve industry issues
Frontier Economics	Blends economics with innovative thinking, hard analysis and common sense	Economic modelling and evaluation and specialist project support across workstreams	Frontier is providing a contribution to the project through a discount in fee rates	Signed a Memorandum of Understanding	Opportunity to apply expertise to solve industry issues

NORTHERN POWERGRID

<table>
<tr><th colspan="6">Project collaborators</th></tr>
<tr><th>Project</th><th>Organisation description</th><th>Project role</th><th>Funding provided</th><th>Contractual relationship</th><th>Partner benefits</th></tr>
<tr><td>Asda</td><td>Large energy user and energy supplier in the retail market</td><td>Provision of flexibility resources from sites located in our two regions.
A purchaser of flexibility to optimise imbalance positions</td><td>Provision of mandays to support the GBFM design and participation</td><td>In process of signing Memorandum of Understanding</td><td>Supports Asda’s existing commitment to optimise energy consumption</td></tr>
<tr><td>KiWi Power</td><td>Commercial Aggregator</td><td rowspan="4">Customer engagement to deliver flexibility services primarily with I&C customers.
Provision of specialist knowledge developed by operating in flexibility markets</td><td rowspan="4">Provision of mandays to support the design process for each Method</td><td>Signed a Memorandum of Understanding</td><td rowspan="4">Opportunity to apply expertise to shape a future flexibility market</td></tr>
<tr><td>ESP</td><td>Commercial Aggregator</td><td>Signed a Memorandum of Understanding</td></tr>
<tr><td>Flexitricity</td><td>Commercial Aggregator</td><td>Signed a Memorandum of Understanding</td></tr>
<tr><td>EnerNOC</td><td>Commercial Aggregator</td><td>In process of agreeing Memorandum of Understanding</td></tr>
</table>

Appendix 5: Base Case costs and comparison of Method and project costs

Base Case method

The Base Case method is the most efficient method currently used to deliver the Solution (that is, to release distribution network capacity) on the GB distribution system. The two methods currently available to release distribution network capacity on the GB system are network reinforcement and bilateral contracting for flexibility services. To establish the Base Case method, we compare the efficiency of these two methods.

Our analysis suggests that the costs of bilateral contracting for flexibility are higher than the avoided network reinforcement cost between now and 2040. This therefore implies that the most efficient method for releasing network capacity currently in use on the GB distribution network is network reinforcement. We therefore use the cost of network reinforcement as our Base Case method.

We now describe the data and assumptions used to estimate the Base Case costs in turn.

The cost of network reinforcement

For the Base Case cost of network reinforcement to the DNO, we use an estimate of £35/kW/year in 2012. This figure is based on the ongoing development of the EHV Distribution Charging Mechanism (EDCM). The EDCM methodology represents the cost of releasing additional capacity on EHV networks, taking into account load levels. We use an estimate based on the more heavily loaded parts of the EHV distribution network. We use a figure that applies to the more heavily loaded parts of the network as these are the parts of the network where capacity release is most needed.

The EDCM estimate of avoided cost cannot be compared directly to the per kW capital costs of network reinforcement (such as those used as inputs to the Smart Grid Forum's Workstream 3 analysis). This is because, rather than taking the average cost of releasing a kW of capacity through reinforcement, the EDCM methodology takes into account the usage levels of the network headroom that is released. Network investments come in large increments, and will often release far more headroom than is actually required. It is therefore appropriate to use the EDCM methodology, rather than the average annualised capital costs.

We assume that the cost of network investment rises by 1% per annum in line with the assumption used in the Smart Grid Forum's Workstream 2 analysis.

The cost of bilateral contracting for flexibility

To estimate the cost of buying flexibility bilaterally we use the current average cost of STOR, the most relevant existing flexibility service. We use National Grid's estimate of the cost of STOR in 2012, of £35/kW per annum. This cost encompasses both availability and dispatch of flexibility We assume that the cost of flexibility remains constant over time as there is a lack of information on which to base any projections.

We make two further adjustments to this estimate of the cost of flexibility.

First we add the transaction costs for the DNO associated with bilateral trading. We estimate that the transaction costs of setting up bilateral contracts for flexibility consist of:

- legal costs, commercial resources and engineering input required to set up flexibility contracts; and
- commercial and administration costs associated with settlement.

Additional costs of bilateral trading might include higher levels of disputes and misunderstanding compared to trading through a market. We do not have an estimate for these costs, so they are not included in the quantitative analysis.

We assume that contracts are for 0.5MW of flexibility on average, and last one year. This provides us with an estimate of average transaction costs per MW of flexibility bought bilaterally.

Second, we make an adjustment to reflect the fact that flexibility services may be associated with a lower level of certainty than network reinforcement. This means that more than one kW of flexibility may need to be purchased for every kW of network investment avoided. The level of confidence that can be attributed to flexibility is being investigated as part of this project. For the purposes of the bid, we assume that DNOs would be able to attribute 67% confidence to flexibility services, in line with the confidence Northern Powergrid currently attributes to steam plant. We scale up the costs of avoided kW of reinforcement through flexibility accordingly. The near term (2017) estimate of the bilateral cost of flexibility therefore consists of £35/kW for availability and use of flexibility, £8/kW of transaction costs, and an additional £21/kW once the cost is adjusted to take into account the lower level of confidence in flexibility compared to network reinforcement.

How the Method costs differ from the project costs and why

The project costs are focussed on trialling the GBFM, to ensure maximum learning on its possible effects and appropriate design. The Method costs are the costs of replicating each Method at project scale. As a result, some costs associated with trialling the GBFM will not be incurred in the Method costs. It is also important to note that there are significant economies of scale associated with roll out of each Method. For example, the costs of setting up the commercial frameworks in Method 1 and the costs of the trading platform in Method 2 will not increase proportionately with roll out.

This section summarises the differences in the cost items included in the Method Costs and the project costs, with an explanation of each difference.

- **Subsidies for the purchase of flexibility.** In the project, parties will be paid a subsidy for supplying flexibility. This subsidy is required to cover the cost in the trial of the actions of providers of flexibility in response to simulated events in each trial. When either Method is rolled out in reality, this subsidy cost will no longer be required, since providers of flexibility will be paid by purchasers of flexibility for their actions. In addition, the subsidy costs budgeted for use during the trials are likely to be higher than the real payments that would be made when the trial is rolled out. This is due to factors such as the inconvenience associated with contracting flexibility in a short term trial, rather than contracting with well-established system, such as STOR.
- **Market and trial design costs.** Costs will be incurred in the first part of the project to develop the design of the sharing frameworks, the markets and the trials. These are one-off costs, which would not be incurred again during roll out.

- **Cost of setting up the multi-party platform in Method 2.** The one-off cost of the multi-party market platform prototype may be greater than the cost of the platform that will be used once the project is being rolled out, due to learning gained during the trials. However, there may also be additional costs associated with replicating the platform for non-trial use. As a result, in our Business Case we have not included the possible savings.
- **Customer participation subsidies.** A budget has been included for subsidies to incentivise distribution customers to participate in the trial. This will not be required during roll out.
- **Costs of collecting and disseminating learning.** The costs of analysing the trial results and disseminating learning will not be incurred during roll out.

Optional Appendices

Appendix 6: Proposed GBFM market design

Introduction

This Appendix describes the market platform which will be developed under Method 2.

The GBFM will be designed for purchasers and providers to trade 'availability' and 'dispatch' of flexibility, through a continuous reverse auction, or similar process. Dispatch is defined as the firm commitment to deliver an increase or decrease in MW output at a given time or location. Availability is defined as an option to buy physical flexibility at any point within defined future windows. Flexibility services include the use of energy storage and DSR programmes utilising distributed generation and/or energy curtailment.

At a macro level the multi-party market design will enable the investigation of the project's Learning Outcomes. Findings from a series of industry workshops held in June and July 2012 and the ELEXON GBFM RFI (responded to by eleven service providers including global IT companies, demand response aggregators and power exchanges) suggest this is one of the most innovative proposals globally at the current time to address the challenge of creating a multi-party flexibility market for demand response and energy storage trading.

To realise the benefits, the design needs to address a number of structural market issues and some behavioural questions:

- the Balancing and Settlement Code (BSC) and the Balancing Mechanism may need to be modified to enable suppliers to participate in a flexibility market;
- TSO reserve products for guaranteed availability windows are historically structured for generation as opposed to the demand side or storage;
- supplier and DNO trading post gate closure may be needed for a flexibility market;
- use of storage for energy trading may put suppliers in imbalance and changes to the BSC may be necessary;
- aggregation of purchasers is currently not available and will require a matching process; and
- I&C customers have multiple potential trading partners (14 DNO regions, TSO, supplier, aggregators) which may be holding back participation in DSR, storage and self-balancing and so new contracting methods may be needed.

Within the market operation design there are also a number of detailed micro-level design options and challenges which the GBFM will investigate:

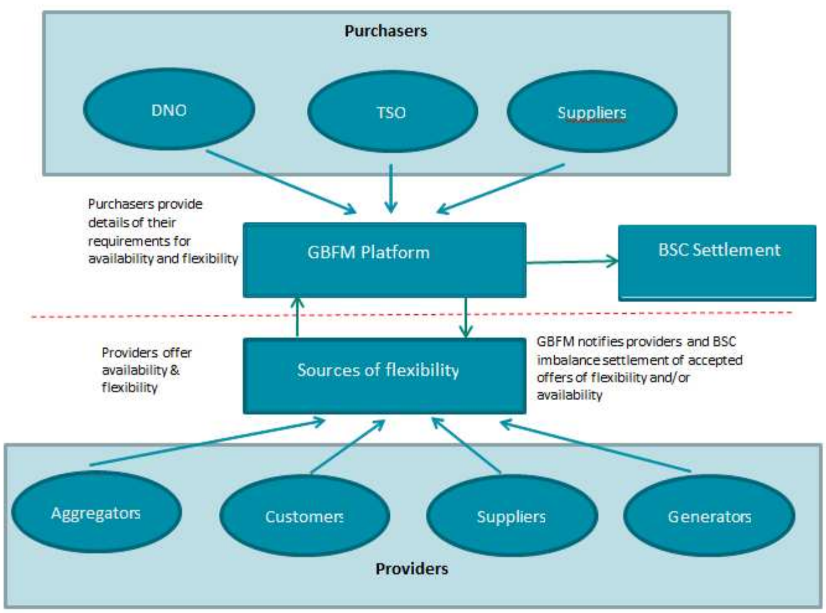
- industry rules and algorithms will be needed to create transparency for TSO and DNO network actions prior to supplier actions;
- optimum product parameters (MWh, response time) for liquidity need to be defined (if these are too prescriptive, too few providers will be able to offer DSR, if they are too loose, aggregation may prove difficult);
- methods for aggregation of purchasers and providers will be required;
- the benefits of trading anonymity compared to naming sites will need to be assessed;
- optimum cost and operational requirements for metering and data collection as well as settlement will need to be developed; and
- a process for matching purchasers and providers will be designed.

Summary of proposed GBFM design

The market platform is summarised in Figure A6.1. It will have the following functionalities:

- ability for purchasers to set product parameters such as kWhs, response times, location and duration;
- ability for providers to respond to purchaser parameters or to unilaterally post availability;
- functionality to match the purchaser's and provider's requirements or to match purchaser and purchaser requirements;
- functionality to allow confirmation and dispatch through sending instructions for dispatch to the provider and sending confirmation for purchaser;
- functionality to allow metering and data collection so that the amount of energy dispatched can be registered; and
- settlement and reconciliation functionality, to allow reconciliation of data and monies from purchaser and provider accounts to be deducted.

Figure A6.1: Proposed GBFM design



An illustrative 'user story'

The following 'user story' is intended to illustrate how these functionalities could work together to allow multiple purchasers and providers to trade flexibility through the platform. The detailed design of the processes will be refined upon commencement of the project.

<u>An illustrative 'user story' – auctioning availability through the platform</u>

Northern Powergrid carries out modelling of how its network will perform over the coming winter, and concludes that peak demand on its Fictional Ridge substation will be sufficiently high that a single circuit fault could leave it unable to satisfy customer demand. To protect against this, Northern Powergrid wants an option to instruct customers supplied through that substation to reduce demand during predicted peak periods over the coming winter.

Northern Powergrid therefore submits a requirement for availability to the platform. This request specifies that they require 40MW of response, delivered at 15 minutes' notice, available between 15:00 and 18:00 GMT over winter weekdays. They need to be able to call on this service once per day. The request also specifies their deadline for concluding the auction (which is in a week's time), the average number of times they expect to call on the service, and a 'reserve price' i.e. the maximum total amount (of availability and utilisation fees) that they would be prepared to pay for calling upon the service that many times. The reserve price is not disclosed to the market.

The platform then publishes anonymous details of this requirement to the market (through email notifications to registered providers, and also through a public website). A number of providers have already offered availability that could help deliver this requirement, but some of these don't cover the full 15:00-18:00 window, and the total volume is in any case less than 40MW. The platform website lists anonymous details of those offers that could contribute towards meeting the purchaser requirement, but indicates that the requirement has not yet been met.

In response to the notification, additional providers submit offers of availability. This is a form of reverse auction process, where all the providers (and potential providers) in the marketplace can see anonymous details of other providers' offerings, and compete with each other to deliver the requirement.

The following day, an aggregator puts in an offer of 30MW of availability. There are now enough offers to meet the total requirement. The platform displays total availability and the utilisation price (which are still above the reserve price at this point).

At this point another purchaser enters the market, as National Grid puts a requirement for short term operating reserve (STOR) into the market. Their total requirement is 100MW, but they break this into four separate 25MW blocks to indicate to the platform that they would be willing to purchase less than the full 100MW.

The platform assesses whether there would be benefit in combining the Northern Powergrid and National Grid requirements into a single auction, but concludes that there would not. The main reason for this is that the STOR requirement is seven days per week, and most of the providers who have been matched against the Northern Powergrid requirement only want to deliver during the week.

The aggregator sees the National Grid requirement and decides to split his 30MW offer into two: a 10MW portion that can only be delivered five days per week, and a (higher priced) 20MW portion that can be delivered seven days per week.

Upon receipt of the new data, the platform reassesses whether there would be benefit in combining purchaser requirements. The platform identifies a package of 35MW of providers that can deliver 30MW for Northern Powergrid and 25MW for National Grid more cheaply than delivering the two separately. It therefore combines the two purchaser requirements into a single reverse auction (and aligns their end dates).

The single reverse auction then continues, with the total price driven further down as providers compete with each other to deliver.

Eventually the auction reaches its predetermined end time, and finishes. The total cost of the package of providers (once apportioned between the two purchasers) is less than the reserve price, so the auction has ended successfully. Purchasers and providers are notified. The providers are now committed to being available in the time windows they specified, and the platform therefore automatically creates offers of flexibility (corresponding to the options they have sold).

Establishing participant requirements for availability

Once a purchaser has identified its own requirement for availability it will come to the platform front-end interface and specify the following:

- the amount of response (MW) - in some cases the requirement may be for reductions in demand (or increases in generation) only and in other cases the requirement may be for either reductions or increases in demand;
- the notice for delivery to call upon the service;
- the date and time window during which they require availability;
- the maximum length of time (in hours) for which they would require the service, and the minimum amount of time before a subsequent request can be made;
- the expected (i.e. mean) number of times the purchaser expects to call upon the service. This is key information that the platform will use when matching providers to purchasers (e.g. a provider with a low availability price but high utilisation price will be more attractive to a purchaser who expects to call upon the service rarely);
- a ‘reserve price’ i.e. the maximum amount that the purchaser is willing to pay in availability and utilisation fees, assuming the flexibility is called upon the expected number of times (this remains confidential i.e. it is used by the platform to decide whether an auction has completed successfully, but is not revealed to providers);
- an indication of the required level of confidence in delivery. A purchaser who is able to tolerate more uncertainty is likely to find their requirement matched at a lower price; and
- the duration of auction.

A transaction reference number will be generated once the purchaser submits their product parameters. This will then be published anonymously to the market. Notifications will then be sent to registered providers via email and/or published on a portal.

In the same way that purchasers can submit their requirements, providers of Flexibility will be able to provide offers of availability. These can be submitted either before or after a relevant purchaser has provided details of their requirement. The required data items are similar to those submitted by purchasers, and will include:

- the amount of available response (MW), which may be positive or negative;
- the required notice for delivery to call the service;
- the date and time windows during which the provider has availability, in terms of the range of dates, times of day and/or days of the week;
- the maximum length of time (in hours) for which they can deliver the service, and the minimum amount of time before a subsequent request can be made; and
- the availability price (£/MW), utilisation price (£/MWh) and startup price (£ per usage incident) associated with the availability.

Matching process for availability

Once the platform has received requirement details from a purchaser, it attempts to match these details with availability submitted by providers (either single providers or via an aggregation of providers). If it cannot match the exact requirements, it will publish further offers to meet requirements. Providers can make offers via a reverse action process. The platform will consider aggregating other purchasers if it assesses the combination to be more cost effective for the purchasers.

The reverse auction format allows providers who can meet the purchaser requirement (in whole or in part) to continue competing until the agreed end time for the auction. Once the end time is reached, the platform will assess whether the providers can deliver the purchaser's requirements at the specified reserve price (or lower). If so the auction has completed successfully, and the platform will send the details to the purchaser and provider. The providers are now committed to provide flexibility during the period. If an aggregation of providers was performed to match the purchaser requirement, each provider will receive the amount they require to deliver. For example, the purchaser requirement could be 100MW to be delivered between 4pm and 6pm and the platform may have aggregated providers to achieve this match:

- provider 1 committing to 100MW between 4pm and 5pm; and
- provider 2 & 3 committing to 50MW each between 5pm and 6pm.

If the auction ends and the platform was unable to match the exact requirements of the purchaser, it will offer the purchaser the opportunity to accept any offers or re-run the matching process. When the purchaser decides to accept an offer it will be assigned a transaction reference number. The transaction reference number may comprise of an aggregation of providers. The availability of each provider will be identified by an availability reference number.

Buying dispatch

The process for buying dispatch of flexibility is similar to that for availability. There are two key differences.

- In certain respects, the data provided by purchasers and providers is simpler, as the product being traded is a firm commitment to change output (without the uncertainty as to how many times the service can be called off).
- Because flexibility may be needed post-fault, it can be traded much closer to real time than availability, up to 15 minutes before the event occurs. Where the platform is provided with sufficient notice of flexibility requirements it will hold a reverse auction. When the notification is given so close to real time that a reverse auction is not feasible, the purchaser requirement will be matched only against those providers who have already notified offers to the system[1].

When a provider has sold availability to one or more purchasers, they cannot offer the same resource as dispatch to other purchasers within that given time window. However, other participants may buy dispatch that has not yet been committed. The platform will flag the committed flexibility by the availability reference number.

Confirmation and dispatch

The platform will issue a notification to both purchaser and provider when availability has been bought. If the purchaser has not yet bought the dispatch for that availability window, the platform will issue another notification to purchaser and provider prior to the availability window taking into consideration the provider's response time. For example if the availability window starts at 4pm and the provider has a response time of 15 minutes, then the platform will issue the notification 20 minutes before; i.e. 3:40pm. Once the purchaser purchases the dispatch, the platform will issue a dispatch instruction to the provider(s).

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[1] In cases where the purchaser has not already bought an availability product covering the time period in question, this may mean the purchaser's requirement cannot be met. But if the purchaser has already bought an availability product they are guaranteed that adequate providers will be available to them in the marketplace (except where providers have become unavailable for technical reasons, or have already been called upon by another purchaser of the availability).

Users will remain anonymous on the market but each transaction between purchasers and providers will be identified via a transaction ID. Alternatively, the participants can each have a unique GBFM reference number when they join the market.

Metering and Data Collection

The use of settlement meters is not feasible for the trial due to the frequency of data being produced on a half hourly basis. Therefore providers will need to have relevant equipment that can produce minute by minute metering. Due to high level accuracy required on the consumption data, it is preferable for an independent party to perform the consumption metered data collection and aggregation. There are two possible options available:

- additional set up for the platform to enable data collection; or
- the DNO can collect the data and pass it on to the platform.

The unit of energy dispatch by the providers will be passed on to the data collector. The platform will use the data to initiate the settlement process.

Note: The RFI provided more information on the feasibility of the two options which will be fully evaluated during the detailed design phase of the project.

Settlement & Reconciliation

Once the data has been aggregated, the system will undertake a settlement process whereby the volumetric profile of energy the provider committed to deliver will be checked against the actual amount delivered within the agreed time frame. The platform will undertake the following:

- determine whether there was aggregation of purchasers, providers or both;
- establish the amount dispatched by each provider against their commitment to the purchasers; and
- where there is aggregation of providers for a purchaser, calculate the amount delivered by the providers and send the purchaser an invoice for their transaction to pay the utilisation fee.

The provider will be paid for the watts of energy delivered at the agreed price from the platform less any charge incurred for non-delivery.

Service delivery assurance

To manage risk to participants, a number of assurance functions will need to be built into the live platform. These will aim to minimise the risk to participants, ensuring compliance with wider industry obligations and regulations. The following functions will be included:

- market entry requirements (to ensure that new participants understand and can comply with the requirements of the market); and
- credit cover requirements (to ensure that providers are paid even if purchasers enter into financial difficulty). The requirements will depend on what types of participant are allowed to purchase flexibility in the market.

A process for measuring the reliability of each provider and feeding the information into the matching process for future auctions may potentially be useful (so that providers with a high probability of non-delivery are not matched with purchasers who require a higher level of certainty).

Trial versus live design

We anticipate that the 'live' design will need to be varied in certain respects to meet the requirements of the trial (because of the need to simulate future market conditions, and the smaller number of market participants potentially involved). Table A6.1 highlights the key differences.

Table A6.1: Comparison of trial and live design

Function	Trial Market Platform	Live Market Platform
Market entry and participation in the GBFM	Decided by project team.	Pre-qualification assessment required to ensure participants have the systems, equipment and can sell energy in the UK.
Product design	Dispatch and availability limited to MW of active energy.	Dispatch and availability with possibility of scope being extended to include other services e.g. Reactive Power.
Number of participants	Restricted to those chosen to be in the trial. Certain market participants will be simulated (particularly where required to reflect market circumstances in 2020 or 2030).	Unrestricted – any entity that meets the pre-qualification. No simulation of market participants.
Purchaser decisions on how much availability and/or flexibility to purchase	Participating purchasers may choose to use an element of simulation e.g. using the platform to manage a simulated constraint on their real network.	Participating purchasers will be making real decisions on what to purchase.
Response required from providers when notified by GBFM that flexibility is required	Real providers will physically respond as they would in the live system (except where otherwise agreed with the project team). Simulated providers will not.	All providers must respond within agreed parameters or face non-delivery charges.
Collateral	No mechanism required.	A similar mechanism to credit cover will need to be implemented to protect participants.

Function	Trial Market Platform	Live Market Platform
Termination of participation	Participants will not be removed from the trial, participants behaviours will be captured as the GBFM project learning.	Breaching the terms of the platform may result in the participant being prevented from future trading on the platform; this could be based on a participant's performance and its risk to other participants.

Summary of RFI responses

Eleven responses were received to the ELEXON RFI document (which was based on a more detailed version of the design described in this Appendix). A number of these responses identified existing market management and demand response management systems that could be configured to deliver the functionality required for the multi-party trial. This gives us confidence that many aspects of the project can be delivered without requiring development of complex bespoke IT systems.

While many aspects of the platform (such as the focus on DNOs) are innovative, some of the providers have experience in similar initiatives in other countries. Respondents provided helpful comments in a number of areas, and we will investigate these further as part of the detailed design of the multi-party trial:

- setting up availability auction gates on different time horizon following a public timeline;
- using a historical rating system for providers to predict unavailability;
- provision of metered data to the platform via a standard specification;
- using optimisation engines to predict probabilities and establish risks to purchasers; and
- additional software for participants that will allow planning, monitoring and control of their energy.

Consideration for the trial

Some responses in the RFI highlighted the opportunities to simplify the trial to save cost. Areas to be investigated during the detailed design for the trial are as follows:

- the use of virtual (cloud) or physical servers and databases;
- starting the trial with limited availability windows focussing on peak hours;
- simplifying the Profile Modelling;
- use of manual processes based on the smaller volume of transactions; and
- accounting for changes to the processes during the trial.

Role of the Operator

During the trial, the main function of the operator will be to facilitate the effective operation of the platform and act as the key interface between the participants and the platform. The role will include:

- informing participants – framework agreement, qualification requirements, services of the platform;
- administering standing data, registrations, quality assurance on transactions;

- supporting participants regarding auction rules and products;
- communicating updates to the trials or functionality of the platform;
- providing assessment and reporting to Ofgem on aspects of the trial; and
- resolving queries and facilitating disputes.

Appendix 7: Trial design

This Appendix presents the Experimental Design methodology which has been used to set the parameters for the trials at this stage. Many of the design choices will be reviewed during the project itself.

To ensure that the approach is robust and that outputs can be evaluated under a range of circumstances, we have:

- carried out an initial Experimental Design process ahead of the trials;
- estimated confidence intervals (CInts) according to conservative assumptions;
- ensured that there are enough substations monitored to ensure the best applicability across GB; and
- planned to build a model of the effects of the Methods before the trials are carried out.

The trial design and likely margins of error have been assessed following advice from Durham University's Statistics & Mathematics Consultancy Unit. This unit will lead on statistical analysis and methodology for the project.

The trials tests the hypothesis that commercial arrangements which allow the sharing of flexibility can create a cost-saving for GB DNOs relative to the current approaches of network reinforcement or bilateral contracting of flexibility. The trials must address the project’s six learning outcomes, in particular, Learning Outcomes 4 and 5.

Criteria for GB DNO suitability

The trials must provide outputs that are directly relevant to GB DNOs. Conditions for the trials have thus been assigned that ensure that the flexibility purchased conform to the criteria set out in Table A7.1.

Table A7.1: Criteria for DNO suitability

Criteria	Settings	Notes
Useful	A 10% general target for peak-reduction at each substation is adopted, locations are chosen according to asset-headroom forecasts	Northern Powergrid has undertaken a study showing that 5% and 10% reductions are typical maxima for substations (mixed and domestic load respectively)
Observable	The peak-load reduction should be greater than 2%	A study carried out for this bid has shown that it is possible to create load profiles for the trial with Confidence-Intervals (CInts) of 1-2% around the time of peak-load
Reliable	The reliability of providers should be determined so that their use for system security can be assessed	40 calls per resource would give a 2.5% resolution on reliability for subsequent use in ER P2/6

Criteria	Settings	Notes
Timely	A specification for flexibility is adopted from CLNR (shift from DUoS "red-zone" to "green-zone"	This entails deferring load from 16:00-19:30 till after 22:00

The location of flexibility services is very important to DNOs. To reduce risk to distribution customers the trials will select primary substations that are forecast to go over firm-capacity within a decade but do not require addressing immediately.

Quantities of flexibility involved

The GBFM trials will involve a range of parties. A design process has been followed for the bid that has assessed the approximate capacity of flexibility that each party could buy and sell during the trials (see Table A7.2 below).

Table A7.2: Approximate quantity of flexibility

MVA	**DNO**	**TSO**	**Direct I&C**	**British Gas**	**Centrica**	**Aggregators**
Purchase	20[2]	<20	-	-	<20	-
Sale	2.8	-	<12	<5	-	<19

Addressing Variability

The GBFM trials have been designed to estimate the ability of the Methods to meet GB DNO needs both now and in the future. We have recognised the trade-off between the accuracy of the trials in estimating the desired outputs against the cost and complexity of the trials. We have also recognised that the desired outputs will be impacted by conditions (e.g. economic and weather); scenarios (e.g. near-term, 2020 and 2030); and the Methods being trialled.

Two of the most important outputs of the trials are the amount of the DNO requirement for flexibility that is met at each substation and the cost of meeting that requirement. It is these that will be extrapolated across GB and will influence the decision to progress to the Method 2 trial and, ultimately, whether either of the Methods is deemed fit for GB DNO use. The confidence that can be placed in these outputs must be sufficient to provide robust decision making.

To ensure the trial design is robust to this challenge, Durham University's Statistics & Mathematics Consultancy Unit has estimated CInts extrapolated from resources according to a hypergeometric distribution. This gives us an estimate of CInts that may be applied to the outputs of the trials. Mean values of costs and reliability are estimated to have maximum CInts of ±30%. These may improve as we understand more about variation during the Project. This would apply also to capacity-released by the Methods in a similar manner to that of ENA ETR131[3].

[2] Based on 10 substations and a 10% general target for purchase of flexibility at each

[3] ENA, Engineering Technical Report 131, "Analysis Package for Assessing Generation Security Capability – Users' Guide", July 2006.

Setting aside night storage load that will be the subject of a specific assessment, there are three predominant load types (domestic, I&C, general mix). The minimum number of substations necessary to assess within-type variation is three in each type. Therefore, a minimum of nine plus one (i.e. ten) substations will be chosen.

During the early stages of the project the choice of ten substations will be confirmed using the latest information from the CLNR project and interim figures for the substations in the trials. To achieve this we will carry out a detailed study of the resources and variability at a few of the chosen substations early in the project.

We will monitor at a further ten substations and use the information collected about each type of resource in a range of different combinations, thus obtaining a spread of results across 20 substations. A study carried out for this bid showed that increasing the numbers above 20 would not significantly increase the coverage of different types of substations or network types.

Selecting Substations

The substations for the trials need to cover a range of predominant load-types (domestic, I&C, night storage, general mix) so that the results of the trials can be applied to GB substations. To make the sample representative the substations also need to cover different geographies (urban, suburban, rural), constructions (underground, overhead, mixed) and other classifications of network and feeder types, such as length. The selection of substations will be undertaken to best cover these (within the constraints of the trials being in NEDL and YEDL), using those substations that are forecast to go over firm-capacity but that do not require addressing immediately.

EES devices purchased by Northern Powergrid for CLNR will be used in the trials as providers of flexibility and equipped with metering equipment to do so. If these are at substations that are not within the selection they will be *virtually* connected to selected substations, on the condition that they could be sited at that location. This same principle will also be applied to other sparse resources used in the trials. Night storage load is treated differently as it could offer significant flexibility in the near term (it is estimated that British Gas alone supplies 200 MW in NEDL and YEDL). The night storage assessment will either physically (there are enough British Gas customers in an area) or virtually (they are too dispersed) connect night storage customers to a predominantly night storage substation. For example, on Denwick primary (peak load 20 MVA) approximately 200 night storage-customers could receive a load-control device, plus supplementary monitoring of comfort. Only one substation will be chosen for physical purchase of flexibility as the sample of 200 is reasonably large; CInts associated with this would be of the order of ±5%.

Obtaining results for all time-frames of interest

The project needs to obtain results for future uses of GB DNOs, hence the need for the 2020 and 2030 time-frames of interest. It also needs to test the technologies that can be deployed today, hence the need to consider the near term. For each Method, the approach will be first to create a parameterised techno-economic model for DNOs use of flexibility resources. One advantage of this is that sensitivities can be examined ahead of trials so that increased attention can be paid to these areas during the trials. The model will then be run (in conjunction with parameter-settings chosen to reflect future scenarios) to predict outputs for 2020 and 2030 time-frames. Where these time-frames require resources to be despatched (or called) in a different manner to that of the near term and the resources are available, the resources will be called in this manner and the outputs used in the modelling process. Further information on the model is given in Appendix 8.

Appendix 8: Market modelling for the GBFM

This Appendix briefly describes the techno-economic modelling we propose to carry out in the GBFM project.

A range of issues will affect the extent to which the trading and sharing of flexibility can reduce costs for DNOs. We propose to use modelling to assess the materiality of each issue before the trials. It is better to identify system risks in a model than to discover them in a physical trial as the trials are limited in terms of the numbers of resources and networks that will be monitored. It is better to approach a risk position with knowledge informed by a model.

To develop a model which is suitable for the purposes of the GBFM project and to exercise the model to create useful insights for the GBFM project, it is proposed to build on the model that was produced by EA Technology to deliver the Smart Grid Forum Workstream 3 report (EA Technology et al, July 2012, *Assessing the Impact of Low Carbon Technologies on Great Britain's Power Distribution Networks*).

Using the model to help with the design of physical trials

During the GBFM trials, it is intended to enable a modification of the power flow through the substation, by calling on one or more flexible resources, such that the total power through the substation or the circuits associated with the substation, does not exceed firm capacity, without having to reinforce the substation. It is not intended to use flexibility resources to enable a primary substation to operate outside of firm capacity[4].

It will be possible in the physical trials to place an arbitrary limit on the power that can be carried by the substation, hence to trigger a requirement for a flexibility resource, or to switch out a circuit and cause an N-1 state on a substation that is over firm capacity. It is unlikely that a fault situation will occur naturally on a substation during the trial. A simulation of a fault situation is by definition a contrived condition, hence the behaviour during that situation is unlikely to be completely reflective of the behaviour during a true fault condition.

It will be impossible in the physical trials to run through every combination of circumstance and therefore to explore every requirement for calling on a flexible resource by each party. It will therefore be difficult to understand every circumstance under which a conflict for use of the resource between different parties will occur.

A model of the market can be used to determine which circumstances should be investigated in the physical trials. This model will require the following capabilities:

[4] Security of supply is key to assessing the suitability of demand side resource. The current security standard for electricity distribution networks is ER P2/6. The core concept of ER P2/6 is the minimum demand that a network must be able to meet after an "N-1" outage. This standard applies where there is redundancy in the capability of the network. "N" represents the number of circuits and "N-1" is a fault situation where one circuit is unable to supply.

This concept is easy to visualise when observing overhead power lines, which typically have three phase conductors (together constituting a 3 phase circuit) on each side of the tower. This is a dual circuit and provides redundancy. This concept is also carried through to transformers in substations. Typically a substation has two transformers, each sized to carry as a maximum, 50% of the load on the substation. Therefore in an "N-1" state, each transformer will be able to carry all the load on the substation. Broadly speaking, "Firm Capacity" is reaches when the maximum power flow through the substation is equal to the rating of one of the transformers.

- knowledge of the probability with which non-DNO parties require flexibility resource, how these requirements are likely to change over time (years), across GB;
- ability to model typical network constraints and the growth of demands on the network due to low carbon technologies;
- knowledge of the time-varying nature of demands on the network (half-hourly) and the time varying nature of requirements for flexibility from non-DNO parties (half-hourly); and
- ability to model the likely incidence of network faults, using industry statistics.

Given these characteristics, the model will step through all combinations of circumstances for calls on flexibility resources from the various parties and identify under which circumstances there is contention and how frequently these occur. This will inform the design of the physical trials which are to be explored in the project, make the trials much more valuable, by concentrating on the most material situations, and inform the market design activities.

This techno-economic model of the market differs from, and will be informed by, the simulation and emulation work which will be carried out by Durham University. The simulation and emulation facilities at Durham University enable a detailed exploration of combinations of feeders which cannot, for reasons of cost, be realised in physical trials. The model that is proposed here is complementary. The outputs from the Durham University simulations would provide better estimates of network constraints on specific network elements under various circumstances, and the techno-economic model would extrapolate the effect of these constraints in combination with the requirements of the TSO and suppliers over wider areas (initially the Northern Powergrid network, ultimately GB) and time periods (e.g. STOR tender round periods).

Aims of simulations using the techno-economic market model

The simulations will have the following four aims:

- to produce a rational, auditable estimate of the probabilities that the actions which flexible resources are called upon to make, are positive, negative or neutral from the perspective of each of the DNO, the TSO and suppliers or energy traders (for example, a call might be positive for TSO and supplier, but negative for a DNO, or positive for DNO and TSO, but negative for a supplier);
- to estimate the probability that a flexible resource could be called on a network which is operating in an N-1 state;
- to determine a likely market value of a DNO procurement of an alternative resource by a DNO, in the event that a flexible resource on a network in an N-1 state is about to be (or has been) purchased by another party; and
- to determine the financial value to a DNO of the flexibility market against the counterfactual of other approaches.

The first two of these aims will help design the trials. The second two will ensure the Methods can be evaluated.

Modelling and simulation milestones

There are seven milestones to this work:

1) the list of flexibility resources to be included in the model and the costs associated with their use will be defined;
2) the probability that each flexibility resource will be used or reserved for use by a party in each season will be modelled;

3) the Smart Grid Forum Workstream 3 model will be extended to provide the required functionality for the GBFM simulations;
4) the probability of N-1 state within each season will be modelled for each representative network type;
5) the probability that a flexibility resource called upon to operate by one party creates a negative impact on another party will be assessed;
6) the cost of negative impacts identified in (4) (identified from the counterfactual alternative method(s) for dealing with the issue) will be assessed; and.
7) the net benefits of the flexibility market will be estimated.

Appendix 9: Transfer into business as usual

A move to a market approach to obtaining flexibility resources as an alternative to network reinforcement for DNOs would have significant implications for DNO businesses.

An important output of the GBFM project will be a road map for the delivery of each of the Methods being trialled. This will include definitions of the activities that would be required to prepare DNO businesses for a move to network operator sharing or to a market based approach. Cost estimates for these activities, which will inform the cost benefit analysis of the project, will also be produced.

The CLNR project includes a set of activities which focus on transferring the learning that is being developed in the CLNR project into business as usual. This will include learning on DNOs' use of DSR. A set of activities are required in the GBFM project to define what is additionally needed to build on the activities in the CLNR project and to ensure DNO businesses are ready to effectively and safely use flexibility resources which are contracted and dispatched via a market mechanism.

This Appendix first introduces the asset life-cycle as a framework for considering the likely impact of the GBFM on business as usual for a DNO, and judges whether the impacts are high, medium or low for each phase of the asset life cycle. It then explores the likely impacts in more detail for the high and medium impact phases. Finally it proposes activities within the project to produce a roadmap to be followed in the event that the GBFM project recommends that a DNO engages with a market to access flexibility resources.

Impact of GBFM on activities within a DNO business

The activities which would be required to prepare the business are determined by consideration of PAS55 and the asset life cycle. Table A9.1 lists phases of the life-cycle and the level of impact of the GBFM outcomes on each of them.

Table A9.1 Asset life-cycle phases

Impact	Asset life-cycle phase	Comment
L	Investment Planning	The impact will be relatively low when factored into the other investment drivers made by a DNO including Non-Load Related Investment, and other types of Load-Related Investment. Investment planning is a high level process and assumptions can be made without detailed knowledge of the solution and how it could be deployed – just that it exists and can be deployed X% of the time.
M	System Planning	Fundamental change in one solution which can be applied, however it is only one of a suite of solutions. It will probably require a change to the Security Standard P2. It is recognised that there are other drivers for an update to P2, which is likely to happen within the lifetime of the project.
M / H	System Design	It is likely to require a change in "mindset" of the system designers.
H	Procurement	There will be an additional role for the Commercial team. Issues will include how flexibility would be treated for the purposes of regulatory income, how the DNO would interface with the market, and whether there will be an impact on DCUSA.
L	Construction	Possible reduction in requirement for new build, no other change.
L	Commissioning	Possible reduction in number of assets being commissioned
H	Operation	Significant impact on Control Room. Big "Trust" issue. Limited or no direct impact on fault teams and field staff.
M	Maintenance	(Of Contracts). The GBFM solution will have a shorter timescale than reinforcement.
L	End-of-Life	Covered within Procurement and Maintenance

The phases which have been rated Medium or High impact are now considered further:

System Planning

It is likely that a change in the security standard (currently P2/6) would be required to enable DNOs to include flexibility resources that are accessed through a market or through sharing when assessing the ability of a network to provide continuity of supply in the event of a network fault. A review of P2 is planned and will happen regardless of the GBFM project. The extent to which the commercial arrangements which are being explored in the project require a change in P2 will need to feed into this process. Whether or not a change is required in the security standard, there will be required changes in System Planning activities to accommodate the potential use of flexibility resources which are accessed through a market in addition to, or in place of, network assets. System Planning is likely to become more probabilistic in nature.

System Design

System designers are not used to including flexibility resources when considering a new design or amending a network in response to a connection request. The use of storage and DSR is being considered in the transfer of aspects of the CLNR project to business as usual. However, an additional and complicating feature of the GBFM is the implication of accessing these resources through a market.

Procurement

There are likely to be significant changes in the entities with which a DNO would contract. So the commercial function of the DNO business will have an additional role. The treatment of "Totex" in DPCR5 allows commercial contracts for the use of resources in place of network capital expenditure to be included in the regulatory asset base.

- How will storage resources be owned and operated? If the resources are DNO owned and operated, then how will conflicts between network engineering drivers and commercial drivers of the DNO be resolved? If the resources are owned and operated by third parties, how will the network engineering requirements pass efficiently and effectively through the commercial interface?
- In addition, will the interface with the market be through the DNO Procurement function and subject to more the general procurement rules and processes of the DNO, or will the interface with the market be with the Commercial and Regulatory Income function of the DNO?
- It is possible that changes to regulatory structures may be required to implement the GBFM into Business as Usual. On the commercial side this might include changes to The Distribution Connection and Use of System Agreement (DCUSA).

Operation

The control room function would probably be significantly impacted by the GBFM. The control room would have to deal with the reality of calling on flexibility resources via the market when managing outages, and will be exposed to the impact of failure of contracted resources to respond. The GBFM will inform operation of the network in an N-1 faulted state and it is anticipated that a revised planning standard would (presumably) accommodate a non-unitary probability of response of flexibility resources whilst providing an acceptable probability of continuity of supply in an N-1 state. The GBFM should also provide learning on the use of flexibility resources for managing outages. A probability of response of less than one means that from time to time a resource will not deliver as expected, which might still be seen as a failure by the control room and could colour the level of confidence which is held in this (new) resource. There is likely to be a strong requirement for visibility within the control room of the resources which can be called upon and the likely / previous performance of those resources. There might also be an impact on the Call Centres' activities.

Maintenance (of contract)

There is a material issue around the confidence that can be placed on the use of a number of resources that are accessed through a market and shared with other parties (assuming that these are in an appropriate location) compared with a single dedicated resource which is directly contracted. The timescales of "market" contracts are likely to be much shorter than asset lifetimes (e.g. National Grid run a number of tender rounds for STOR every year). Assuming that these confidence issues can be resolved, there could be a significant contract maintenance issue, when compared with the "fit and forget" of reinforcement. This would impact Commercial and / or Procurement departments.

Regulatory issues

In addition to the internal business changes, there will be a need to interact with Ofgem to ensure that any regulatory changes that are required to implement the proposed changes can take place. These will be initially discussed on a bilateral basis and they could potentially be addressed through the Innovation Roll-out Mechanism, which is proposed as part of the Innovation stimulus package in RIIO-ED1. Any learning implemented during RIIO-ED1 will of course be built into planning assumptions and solutions for RIIO-ED2.

Activities proposed for the GBFM project

The GBFM project will not directly address the issues described in outline above. Rather the project will investigate the materiality of the issues that have been identified, flush out any additional issues and produce a roadmap for implementing the recommendations of the project. It will also produce cost estimates for implementing the roadmap, which will inform the cost benefit analysis to be carried out within the GBFM project.

The proposed activities are now described for each of the asset life-cycle phases which have been rated Medium or High impact. For each stage, estimation of activities, resource requirements and timescales would also be included.

The following activities are proposed for System Planning:

- understanding of the extent to which a change in the security standard (currently P2/6) would be required to enable DNOs to include flexibility resources that are accessed through a market when assessing the ability of a network to provide continuity of supply in the event of a network fault;
- identification of the changes to Northern Powergrid policy and procedure documents that would require changes to implement the outcomes of the GBFM within BAU System Planning activities;
- production of a document describing how the GBFM could impact on system planning;
- identification of enhancements to the planning processes and to the tools which support these processes which would be required; and
- identification of education and training requirements for System Planners and production of an education and training plan.

Three activities are proposed for System Design:

- identification of the changes to Northern Powergrid policy and procedure documents that would require changes to implement the outcomes of the GBFM within BAU System Design activities;
- identification of enhancements to the system design processes and to the tools which support these processes which would be required. Estimation of activities, resource requirements and timescales for implementing the enhancements; and
- identification of education and training requirements for System Planners and production of an education and training plan.

The following activities are required for Procurement:

- planning, carrying out and documenting engagement with relevant staff within the Customer Operations Directorate, Regulation Directorate and Procurement. The aims of this engagement would be:
    - communication of the possible outcome of the GBFM and what this could mean for the operation of a DNO, including the impact of short-term contracts agreed via a market;

    - identification of requirements and barriers to engaging with a flexibility market, from the perspective of each Directorate (or section within each Directorate); and
    - exploration of the materiality of issues raised;
- organisation of a workshop to present the findings, debate and agree responsibilities of different areas of the business when interacting with a flexibility market;
- identification of any changes to commercial /regulatory / procurement procedures and systems that would be required to facilitate engagement with the flexibility market;
- identification of timescales for revising descriptions of responsibilities, any organisational structure changes and implementing the changes, including any formal consultation that is required; and
- identification of education and training requirements for commercial engineers / contracts managers / procurement specialists and production of an education and training plan.

For operation, the following activities would be required:

- production and circulation within Northern Powergrid, of a document describing how the GBFM could impact on control and operation of the network;
- one or more workshops with staff to communicate the possible outcome of the GBFM and what this could mean for the operation of a DNO. These workshops would aim to paint potential scenarios, identify the concerns of staff, that are associated with the control function, over any perceived change of risk which is associated with the GBFM; and understand which issues are most important;
- assessment of how to address the identified material risks and enable practical roll-out;
- identification of education and training requirements for staff associated with the control function and produce an education and training plan. This should include "learning by doing in a safe environment"; and
- identification of any changes that control engineers require to provide them with a timely view of the status of available flexibility resources and how these could affect network status and planning for changes to ENMAC and / or GUS.

In addition the following regulatory activities would be required:

- contribution to industry group in drafting of revision to the security standard P2 (if required);
- contribution to industry group advising and interacting with DCUSA ltd (if required); and
- interactions with Ofgem to discuss regulatory impacts.

Overall this would allow the consolidation of the outcomes of the activities into a coherent plan, recognising synergies which could be used to make the transfer into BAU more efficient and effective than a piecemeal approach. A timeline and phased cost estimate for transfer into business as usual could then be produced.

Appendix 10: International review

We have carried out a review of international experience of flexibility markets which include DSR. This review aims to ensure we can build upon lessons learnt from the most important existing flexibility markets, and that we are not duplicating work in this area. The review looks at experience from the following markets and trials:

- **Existing markets:** PJM, California ISO and ERCOT in the USA; AESO in Canada; Nord Pool in Europe; France's market; and the National Electricity Market in Australia.
- **Trials:** the Twenties virtual power plant (VPP) project in Denmark; National Grid's Demand Turndown trial; ISO New England's Pilot Programme; and the ADDRESS project in Europe.

While the review aims to cover the main existing flexibility markets, we intend to investigate international experience further once the main project begins.

The following main messages were found in the review.

While there is some international experience of running or trialling flexibility markets which include DSR, new learning will be provided by the GBFM due to its core focus on reducing distribution network costs. Most other markets have focussed on the provision of balancing services.

- Flexibility services such as DSR have been included in a range of electricity markets. For example, PJM in the USA includes DSR in its real-time and day-ahead energy and reserve markets. However, this market is not focussed on reducing distribution network costs.
- The Twenties project set up and is running a virtual power plant (VPP) in Denmark, which provides ancillary services to the Danish transmission system operator. This market differs from the GBFM in that it does not focus on reducing distribution network costs.
- The Australian Energy Market Commission (AEMC) reviewed participation of DSR in the National Electricity Market (NEM). The aim was to improve efficiency of investment in electricity services including the distribution network (Crossley, 2011).

Existing flexibility markets have included a broad range of flexibility providers from the demand side. However, we did not find any evidence of electricity energy storage (EES) participating in these markets. For example, the VPP set up in the Twenties project includes (amongst others) heat pumps, drain pumps, diesel generators and hydro power units.

DSR may be best suited to providing ancillary services that do not require a very fast response. Some markets, for example AESO, exclude DSR from providing services which required a response within seconds of the resource being notified, such as frequency response. PJM allows DSR to provide services requiring a rapid response, but current participation by DSR resources in this part of the market is low. For example, no DSR cleared in the day-ahead scheduling reserve (DASR) market in January – March 2012.

Reliability requirements may be a barrier to flexibility providers competing with traditional providers of these services. PJM limits participation by demand resources in some of its markets to 25% of the total procurement in each region. Demand resources in PJM's synchronised reserve market are all allocated a lower priority, and are only used in periods where higher priority resources (such as generation) are insufficient to meet the reserve requirement. National Grid's Demand Turndown trial found that the

DSR delivered when units were called upon was 47 – 83% of the amount declared available. ISO New England's trial found low reliability of small demand resources when they were called upon frequently to provide ancillary services in emergency conditions. There was limited information on the reliability of DSR in other markets.

Arrangements for providing DSR need to be carefully designed, as there may be logistical or information barriers. National Grid found that, despite high initial interest from aggregators, actual participation in its Demand Turndown trial was lower than designed for, due amongst other reasons to resourcing difficulties over the relevant timescale. Participation by DSR in PJM's electricity markets has increased over time since their initial inclusion, and in the Nordic and Texas electricity markets, demand resources represented around half the total requirement for contingency ancillary services (Heffner et al, 2007).

Most markets have defined DSR participation relatively narrowly. There was typically one purchaser of flexibility in the markets we found, and relatively narrow product definitions. For example, DSR resources in PJM's markets are required to be enrolled in their Economic Load Response programme to qualify for participation, with further restrictions in individual markets.

The preferred remuneration arrangements for supplying flexibility may differ between types of provider. The Twenties project found that production units in the VPP knew the structure of the electricity markets well, and expected payment for their services to correspond closely to market prices at the time of delivery. In contrast, consumption units knew the structure of the electricity markets less well, and valued predictability of payments. As a result, the settlement arrangements differed between production and consumption units. Similarly, a review by Heffner et al (2007) found that demand resources providing ancillary services preferred a steady revenue stream. This difference in the expectation of parties suggests that outcomes could benefit if an intermediary such as the GBFM platform was introduced.

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Appendix 11: Potential collaboration with UK Power Networks

In this Appendix, we discuss the potential for collaboration with UK Power Network's Smarter Network Storage (SNS) project, which is also bidding for Tier 2 LCNF funding this year. UK Power Networks and Northern Powergrid have jointly identified potential synergies between the SNS and the GBFM projects.

Specifically, Northern Powergrid and UK Power Networks (UKPN) offer the opportunity for some work activities to be undertaken jointly during the detailed design phases of systems. The benefits of this are that it will ensure common interfaces and data exchange requirements are considered and developed in a way that supports future integration. Any costs of future integration towards an end-to-end efficient market system for flexibility could therefore be minimised.

Both projects aim to address current challenges in unlocking the full value of electrical energy storage (EES) capacity. They will assess how EES capacity can support the needs of distribution networks while maximising the potential value for other parts of the electricity system. The projects will help to understand the feasibility of future business models and technical solutions which could allow energy storage to play its part as a source of cost effective flexibility on the electricity system. The collaboration could potentially unlock significant benefits, providing both projects with the opportunity to develop, challenge and agree concepts and conclusions using the resources and experience of both companies.

The Northern Powergrid CLNR project is developing control systems that will support the use of storage capacity for DNO requirements. In the GBFM project, technical and commercial systems which allow services from this storage to be shared and traded with other parties will be trialled. The smart control and optimisation system proposed within the SNS project will also support the use of storage capacity for DNO requirements, while also allowing automated optimisation and scheduling of this flexibility for other system participants. The SNS system aims to improve the efficiency and increase the value that can be delivered by the storage by allowing it to be used by other parties when unused by the DNO. The systems being trialled in both projects, underpinned by new control room functions, will be important at the distribution-network layer in the future, when more active DSO's or third-party providers may have portfolios of flexibility sources including storage and DSR. The opportunity for the projects to collaborate, sharing previous CLNR experience and combining SNS & GBFM resources, could benefit both projects. In addition, the dissemination process would be enhanced if jointly produced and presented by UK Power Networks and Northern Powergrid.

Initial discussions between UK Power Networks and Northern Powergrid on the potential for collaboration have taken place at a conceptual level. The option of fully integrating the two projects to deliver cost reductions has not been considered on the basis that the GBFM project already has significant delivery complexity with seven strategic partners and five collaborators, and the SNS project will resolve specific network constraints which requires the installation of localised assets. However, at this stage, we expect that considering interfaces and integration during the design phases and delivering joint dissemination sessions would not result in an increase in cost across the two projects. Our view is that this collaboration would help increase overall benefits and contribute to a more rapid transition to a low carbon economy.