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GB Electricity Demand – *realising the resource*

Paper 4

What Demand-Side Services Can Provide Value to the Electricity Sector ?

By Judith Ward, Maria Pooley and Gill Owen
Sustainability First

June 2012

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Sponsored by : BEAMA ; British Gas ; Cable & Wireless; Consumer Focus ; EdF Energy ; Elexon ; E-Meter Strategic Consulting; E.ON UK ; National Grid ; Northern Powergrid ; Ofgem ; ScottishPower Networks ; UK Power Networks.

Smart Demand Forum Participants : Sponsor Group ; Energy Intensive Users' Group ; Which? ; National Energy Action ; Brattle Group ; Lower Watts Consulting ; DECC ; Sustainability First.

Project Background

Sustainability First is a UK environmental think-tank with a focus on practical policy development in the areas of sustainable energy, waste and water. Sustainability First undertakes research, publishes papers and organises policy seminars. It is a registered charity with independent trustees – www.sustainabilityfirst.org.uk.

Since 2006, Sustainability First has produced a series of major multi-sponsor studies on GB household smart energy meters and brings significant knowledge and insight in the fields of energy efficiency, smart metering, smart energy tariffs and demand response[1].

The Sustainability First project on **GB Electricity Demand** began in April 2011. It is supported in its first year under the Northern Powergrid Low Carbon Network Fund project - and thereafter for a further two years to April 2014 via a multi-sponsor group.

Sponsors include : BEAMA ; Cable & Wireless; Consumer Focus; British Gas ; EdF Energy ; Elexon ; E-Meter Strategic Consulting; E.ON UK ; National Grid ; Northern Powergrid ; ScottishPower Networks ; UK Power Networks.

Work is coordinated through a **Smart Demand Forum** whose participants also include a number of key consumer bodies: Energy Intensive Users Group, Which?, and National Energy Action and DECC, plus the sponsor group members.

The project aims to identify the potential resource which the electricity demand side could offer into the GB electricity market through demand response and through demand reduction. The project aims to:

- Evaluate and understand the potential GB electricity demand-side resource across all economic sectors (including the role of distributed and micro-generation) ;
- Develop a clearer understanding of the economic value of this resource to different market actors and to different customers over the next 10-15 years ;
- Evaluate the key customer, commercial, regulatory and policy issues and interactions.

[1] Sustainability First published smart meter papers are available on the website – www.sustainabilityfirst.org.uk

The project will develop a substantive knowledge-base, and provide visibility and thought-leadership for GB electricity demand-side issues. The project is undertaking work relevant to:

- GB smart meter deployment.
- Low Carbon Network Fund projects – emerging lessons and insights from the LCNF projects will be fed into the project
- Proposals for Electricity Market Reform

The work programme is being delivered through the Smart Demand Forum, through annual wider stakeholder events, and through a series of published papers and other materials. The project is run by Sustainability First. The Sustainability First team is Gill Owen, Judith Ward and Maria Pooley.

Additional expertise and inputs are provided by Serena Hesmondhalgh of Brattle Group who is developing a quantitative all-sector demand model. Stephen Andrews is supporting the project on Distributed Generation and Micro-Generation.

Key themes for the project include:

- **Customer Response and Consumer Issues –** A key focus for the project is to understand successful and cost-efficient demand-side participation from a customer and consumer perspective (household, industry, commercial and public sectors). This will include experience provided through the LCNF trials (e.g. tariffs, remote control of appliances, technologies such as micro-generation, electric vehicles etc.) and other similar initiatives in the UK and elsewhere. For households, this will include any particular issues for the fuel poor and potential distributional impacts.
- **Commercial** - Practical realisation of demand-side services - given different roles and requirements in the value chain. Issues likely to include : the nature of commercial agreements, the role of third parties,(DNOs, ESCOs, aggregators) the kind of information-sharing likely to be necessary between parties etc. – drawing from practical experiences of the LCNF Trials and other experience in the UK and elsewhere.
- **Regulatory** – near and longer term regulatory factors that impact upon development of an active electricity demand-side for Great Britain – including current agreements between market actors, statutory codes, incentives in price controls, settlement, and third-party requirements. This will include experiences within the LCNF trials, and also feed into future considerations for price controls, RIIO and other thinking on innovation incentives.
- **Public Policy Issues** – likely economic value and potential contribution of the demand side to: cost-efficiency across the electricity sector; security of supply; carbon-emission reductions. Business models, approaches and incentives for integrating the demand side into the electricity market, including its interactions with Electricity Market Reform, smart meter roll-out and energy efficiency schemes such as the CRC Energy Efficiency Mechanism, Green Deal and Energy Company Obligation.

The project will also draw upon relevant information from demand side developments in other countries (notably the EU and US) to inform its work.

Papers published in the first year of the project are:

Paper 1 - GB Electricity Demand in 2010 - baseline data and context. Published October 2011.

Paper 2 - GB Electricity Demand 2010 and 2025. Initial Brattle Electricity Demand-Side Model - Scope for Demand Reduction and Flexible Response
Published February 2012.

Paper 3 - What demand-side services could GB customers offer in 2010?
Interim Industry paper published March 2012 (final paper to be published in July 2012).
Household paper published May 2012.

Paper 4 - What demand-side services can provide value to the electricity sector? Published June 2012.

All papers are available from on website at:
http://www.sustainabilityfirst.org.uk/gbelec_documents.html

The first two papers in Year 2 will be:

Paper 5 - The electricity demand-side and wider policy developments

Paper 6 - The electricity demand-side and distributed generation

Topics for papers in future years are likely to include:

- Evolution of commercial arrangements, alignment of commercial drivers, regulatory incentives and prospective business models for development of a more active electricity demand-side
- Electricity demand and consumer issues
- Active I&C Customers
- Active Household and Micro-business Customers
- Longer-Term Demand-Side Realisation and Innovation

Sustainability First
June 2012

Paper 4 : What Demand-Side Services Can Provide Value to the Electricity Sector ?

June 2012

GB Electricity Demand – ***realising the resource***

Paper 4

What Demand-Side Services Can Provide Value to the Electricity Sector ?

This paper draws on discussion with market actors on a non-attributable basis – for which we are most grateful. The paper aims for a balanced account of those discussions – and responsibility sits with Sustainability First.

Section III includes some initial insights and findings.

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List of Annexes

Preface

1. This paper aims in an initial way to consider how customers might begin to provide more by way of Demand-Side Response (DSR) services to market actors.

2. The main focus of this paper is therefore on the benefits and potential value of DSR in different parts of the electricity market as it is organised today. This is in expectation that if there is value available to market actors from avoided-cost actions of DSR, then potential revenues are also available to share with customers and consumers. This paper does not focus on electricity demand reduction.

3. The paper pulls together a great many issues arising in discussion with thirteen market actors who kindly made time available : 4 DNOs ; 5 suppliers ; system operator ; system settlement agent ; aggregator ; power exchange.

4. Discussion was non-attributable – and responsibility for the topics mapped out – including the initial 'Issues' Section III – sits fully with Sustainability First.

5. The paper covers a great deal of ground. It is neither comprehensive nor definitive. In particular, Section II on 'Understanding DSR Values' will be re-visited.

6. Issues identified in Section III, will be explored further in future papers for the Smart Demand Forum.

Introduction

7. In Paper 1, we outlined at a high level how GB load management / demand-side schemes are operated today by :
   - National Grid as the GB System Operator – for frequency response and reserve services.
   - Distribution Networks – for improved fault management ; for deferred or avoided network reinforcement.
   - Suppliers - flexible / time-varying pricing for I&C customers ; support to their customers in their TRIAD management.
   - Aggregators

8. On the demand-side, the Brattle model in Paper 3 suggests *technical* potential for shiftable load today across all sectors as follows :

   - January weekday winter evening : ~18GW of 54GW load (ie ~one-third of load).
   - August weekend evening : ~10 GW of 35 GW load (similarly ~one-third).

9. Paper 3 on Industry and Household electricity demand, starts to explore from a customer and consumer viewpoint, why there may be a sizeable gap between such high-level modelled estimates of technical potential for demand response – and today's customer interest in demand side participation, including the value on offer to customers.

10. This paper - Paper 4 – draws mostly from discussion with market actors[2]. It considers, mainly from their perspective :
    - Current market actor interest in demand-side response : what DSR do market actors procure today and why[3].
    - Likely value of DSR today to market actors - and therefore potentially to their customers.
    - Issues for market actors in realising DSR potential today, including emerging issues for policy and regulation in realising unexploited DSR potential today and looking ahead.

[2] System Operator, Elexon (settlement system agent), 4 DNOs, 5 Suppliers, 1 Aggregator, 1 Power Exchange.

[3] This paper does not focus on issues relating to electricity demand reduction.

I Market Actor Interest in Demand-Side Response Today

1. In today's GB electricity market, the total demand-side contribution is modest, with perhaps only 1-1.5 GW contracted in the market in some way[4]. This sits against an installed GB generating capacity of ~80 GW and a maximum winter peak of ~58GW .

2. GB demand-side response activity is developing, driven by a mix of :

   - Commercial interest from both new demand-side actors and by existing players ;
   - Market actor trials ;
   - New thinking on how to enable demand-side participation in the proposed GB capacity market.
   - Interest from policy-makers

3. A Chart of demand-side schemes in today's GB electricity market is in Annex 8.

4. We discussed with thirteen market actors (system operator, Elexon (settlement system agent), suppliers, distribution networks, aggregator and power exchange) what role DSR plays for them today and why. This section looks in turn for each market actor:

   - **Main reasons for DSR**
   - **DSR value**
   - **Key issues in discussion**

[4] 'True' demand-response across entire market, probably ~4-600 MW (see para 10).

System Operator Interest in DSR

System Operator - Main Reasons for DSR

1. By volume and value, most GB DSR today is contracted by the system operator.

2. National Grid procures a range of balancing services from larger generators[5] and from a mix of smaller generators and the demand-side[6] to help balance / regulate the national electricity system in short-term operational timescales.

3. Tenders open to demand-side participation (non-BMUs) include[7] :

   - **Frequency Response** : Firm Frequency Response ; Frequency Control by Demand Management.
   - **Reserve Service** : Fast Reserve ; STOR (Short Term Operating Reserve) ; Demand Management.
   - **System Security Service** : Transmission Constraint Agreement[8] ; Inter-trips.

System Operator – DSR Value in Balancing Services

4. Total annual charges for electricity transmission represent around 4% of an average household customer end-bill with Balancing possibly representing ~ 1%. That is, ~£2.5bn annual charges for both TNUOS (Transmission Network Use of System) and BSUoS (Balancing Services Use of System) combined, with annual balancing costs amounting to around £750 million. As system operator, National Grid is incentivised to

[5] Balancing Mechanism Units – BMUs. Participants in the national Balancing Mechanism arrangements.

[6] Non-Balancing Mechanism Units.

[7] See Annex 1 for more detailed National Grid description.

[8] Currently no active DSR participation in Transmission Constraint Management. See para 16.

deliver the efficient, economic and coordinated operation of the transmission system – and is incentivised accordingly under its Balancing price-control by Ofgem.

5. National Grid identify the main balancing services in which DSR in principle can participate. In procurement terms, these amount roughly to the following annual expenditure[9]:

- Response - £193 m
- Fast Reserve - £92 m
- STOR - £98 m
- System Security Service - £324 m (Transmission Constraint Agreement[10] ; Intertrips).

6. Total value of balancing services in which the demand-side (non-BMUs) can in principle participate therefore amount to £383 million excluding Transmission Constraints.

7. For the demand-side, active markets are for Frequency Response, Fast Reserve and for STOR (Short Term Operating Reserve).

8. Demand-side STOR providers are a mix of large industrial customers – and energy suppliers and aggregators - who bring together smaller loads across sites and offer these to National Grid as a single STOR unit. In 2011-12, very roughly one-half of STOR by contracted capacity was provided by non-BM Units[11].

9. For their 2011-12 total 'Operating Reserve' requirements of 4.7 GW, National Grid has non-BMU demand-side contracts for ~1500 MW – i.e. some 20-25% of their requirement.

10. Three-quarters of non-Balancing Mechanism Unit STOR provision is estimated to be provided by on-site back-up generation. 'True' demand-side services contracted to

[9] From March 2012. See also : Summary of BSIS costs. Monthly Balancing Services Summary 2011-12. February 2012. National Grid. p.26

[10] See para 16 on Transmission Constraints. Currently no active DSR participation – and would in many ways be a challenge for DSR providers.

[11] In the early part of 2012-13, National Grid procured ~2.8 GW of Short Term Operating Reserve, of which : 45 % by contracted capacity were Balancing Mechanism Units – i.e. large generators ; and 55% Non-Balancing Mechanism Units. Of non-BM Units the split was approximately : 87% Back-Up Generators ; 13 % 'true' demand-side .

National Grid for Short Term Operating Reserve are understood to be nearer to 200 MW – representing a modest proportion of total Operating Reserve services currently[12].

11. STOR bidders offer prices for (1) availability and (2) for usage. In March 2012, the average availability price was ~£10.00/MWh and average utilisation price of ~£224/MWh[13].

12. Some indicative revenues for STOR providers in 2012 were outlined as follows[14].

    10 MW committed contract :
    Availability Revenue - £260k firm revenue (6 seasons year 1 – assuming £7/MWh availability fee and full availability for 3,700 hours).
    Utilisation Revenue - £40-£160k variable revenue (20-80 1 hour 'calls' in Year 1 assumed £200/MWh utilisation fee) .

    25 MW committed contract :
    Availability Revenue - £650k firm revenue (6 seasons year 1)
    Utilisation Revenue - £100-£400k variable revenue (20-80 1 hour 'calls' in Year 1)

    50 MW committed contract :
    Availability Revenue - £1.3 million firm revenue (6 seasons year 1)
    Utilisation Revenue - £200-800k variable revenue (20-80 1 hour 'calls' in Year 1)

13. It is on the basis of such potential revenue streams, that aggregators (inter al) are seeking opportunities today to expand the non-BMU share of balancing services market

[12] Other 'true' demand-side services provide further contributions in the market for Fast Reserve (50-300 MW) and for Frequency Response (approx. 80-90 MW).

[13] Source – National Grid. See Short Term Operating Reserve Annual Market Report 2010-11. p.1 for earlier prices.

[14] Source – National Grid

See also National Grid slide set 'Demand Side Opportunities. Graham Hathaway'. July 2009.
- where other indicative revenues (in 2009) were :
Fast Reserve –£/MW pa - £50k/MW pa : Availability / Holding - ~£44k per MW/pa. Utilisation (non-BMU) ~£6k/MW pa
Frequency Response – £/MW pa - Availability - £34k/MW pa. Positional fee - £22k/MW pa. Response energy fee - £/MWh

provision. In the past year, non-BM provision of STOR services has increased from around two-thirds to just over one-half today. By volume of contracted capacity, this provision is very largely back-up plant (87%), rather than 'true' DSR (13%).

System Operator – Key Issues in Discussion

14. In discussion with market actors, some issues on DSR and on STOR (in particular) were:

- Total expenditure on STOR in 2011-12 was £98 million. However, in relative terms, greatest earning potential for demand-side providers may be likely from providing Frequency and Fast Reserve – both today - and looking ahead to a future with more wind. Frequency and Fast Reserve require much faster 'technical' response times than STOR – but shorter duration[15].

- National Grid provides much information to would-be participants about the STOR tender process. However, would-be DSR participants nevertheless expressed a desire for more transparency.

- STOR enables Non-BM Units a choice of committed and flexible contracts[16]. DSR providers with flexible contracts can opt out a week-ahead (with an associated earnings loss).

- The STOR tender assesses value and costs. Additional considerations include: response time; location; reliability[17].

15 See Annex 8 for detailed description of technical requirements for Frequency Response and Fast Reserve.

16 STOR B-M Units – must offer 'committed' service. Non B-M Units may offer 'committed' and 'flexible' service (also, 'optional' service outside STOR windows). For 'committed' service, must be available in every service window across a season, with service windows typically being between 07.30 and 14.00h – and 16.00 – 21.30h. For 'Flexible Service' - indicative total hours of availability are tendered – but – actual availability declared week-by-week at providers discretion. There are three tender rounds p.a. for service periods ranging from 8 weeks to two years. In 2011, Long-Term Committed Service tender offered by National Grid for two tender periods for service periods of up to fifteen years.

17 STOR Technical requirements include: Minimum contracted MW capability of 3 MW. MW must be delivered in no less than 240 minutes after notice (ideally, delivered within 20 minutes). Deliverable for at least 2 hours. Contract for one or two years.

- STOR requirements are high at weekends – as well as weekdays – including in periods either side of peaks, each day. STOR requirements are also significantly locational – for example, STOR units are preferred in England and Wales rather than in Scotland due to north-south system constraints. Each of these factors serves to narrow the prospective suitability of providers in STOR, including DSR providers.

- Recently, increased competition in the STOR tender has (1) created less predictability in STOR prices for those tendering and (2) led to lower availability payments. Such competition helpfully serves to reduce the overall costs of system balancing – but, at the same time, potentially, reduces earnings available to would-be DSR providers in STOR.

15. Market actors are currently getting to grips with both technical and commercial questions relating to the interaction and 'hierarchy' for DSR services in different parts of the electricity system . For example, participation in STOR, TRIAD and / or DNO fault management etc. This includes developing a better understanding of the relative earning streams which may be available to customers from avoided-cost values from DSR.

16. Transmission Constraint Management – National Grid's annual costs of managing transmission constraints are currently ~£300m and have been increasing with more wind commissioning, especially in Scotland – and associated upgrade works of the transmission system. National Grid seeks to reduce constraint costs via locational contracts – but currently there is no DSR provision. The characteristics of constraints tend to require a service for extended periods - every day, possibly for weeks or months - which could prove challenging for a DSR provider. Moreover, constraints may be one-offs – or not re-occur for a number of years – so may offer a DSR-provider little prospect of revenue continuity.

17. National Grid's Balancing activity is shaped by its Licence principles to achieve the efficient, economic, and coordinated operation of the transmission system. In principle therefore, as system operator, National Grid is indifferent as to whether the Balancing services it procures are from generation or from demand-side.

18. In practice however, as noted in the paragraphs above, a variety of considerations – technical, locational, availability, prospective reliability, and scale – come into play in the procurement of Balancing services.

19. For historic reasons, these practicalities have tended towards generation – albeit National Grid is clearly open to greater non-BMU participation, including demand. However, from the customer side, some issues touched on here need further consideration if demand from larger customers is to more readily access the potential revenues which the Balancing market may offer to them.

Supplier Interest in DSR

Suppliers – Main reasons for DSR

20. Suppliers have an in principle interest in DSR – but currently undertake relatively little demand-side response activity. Rather, suppliers are seeking to understand and to learn.

21. Suppliers are exploring what additional benefit DSR might bring to their business, including how DSR may fit with wider demand-side development (Energy Management Contracts, ESCO activity, electricity efficiency).

22. We consider possible barriers in section III, but it is important to note that supplier incentives for development of DSR opportunities with respect to potential cost-savings from avoided wholesale costs - capital expenditure and / or energy-related (commodity) costs - seem poorly aligned.

23. Three consistent themes in discussion with suppliers were that :

- **Many costs in the market are socialised among all market actors** – so it is hard for suppliers to realise commercial advantage from any particular demand-side actions they may initiate. Initially, development of more and better load-profiles - followed in due course by the potential option to settle half-hourly once smart meters have been rolled out and the DCC[18] is operational - were seen as central to unlocking greater DSR activity on a commercial-scale for suppliers.

- **Separation of distribution and supply** - and / or arms-length relationships between different parts of an integrated energy company - make it a challenge to realise potential savings from DSR. Although in principle savings should be available – e.g. wholesale savings through to the supplier arm of the business – in practice, currently, any such savings seem difficult to realise. New and innovative commercial arrangements between DNOs and suppliers will need to redress this (e.g some LCNF trials are addressing this issue).

- **The Balancing Mechanism price-calculation leads suppliers to be risk-averse and over-contract for generation.** This 'bias' to over-contract for generation, serves to inhibit demand-side initiatives / actions.

[18] Data Communications Company

24. **Integrated Suppliers**[19] - are exploring the role of DSR. Suppliers potentially do see scope to develop value from DSR in combination with a variety of new customer 'offers' – via energy services and sales of low-carbon technologies. There may nonetheless be some tensions between the upstream and downstream arms of the business. One such consideration may be that DSR could dampen prices in STOR otherwise available to BM-Units and / or smooth prices in the wholesale market - and so perhaps reduce available generator revenues.

25. **Independent Suppliers**[20] – see potential benefit of DSR in :

- **Flatten / smooth peaks and / or wind-related price volatility** – and so avoid contracting for / procuring generation at highest-cost periods – but – first need to address current considerable risk of being under-contracted for generation. Currently, for risk-averse reasons – i.e., to avoid risk of paying high imbalance charges, suppliers tend to over-contract for generation – rather than look towards DSR. (This was seen as a function of the imbalance price calculation which, it was suggested, could potentially be addressed).

- **Balance renewables / PV - within house / within community.** However, until more and / or better-shaped load profiles become available for households – and / or half-hourly settlement – a supplier cannot realise the full benefit of optimising an individual household customer's load.

26. Some examples of current supplier-led DSR activity are in Annex 2. Suppliers are already engaged in some limited DSR-related activity via :

- **Flexible Contracts** - suppliers offer a variety of contracts to their I&C customers (or their brokers) – both half-hourly - and non-half hourly settled. These may incorporate time-varying pricing for base-load, peak and seasonal pricing.

[19] Integrated supplier – energy company with both generation and supply business

[20] Independent supplier – energy company with supply business only.

Example:

One example of innovative contracting by a supplier, is in offering a flexible product that allows the larger (30GWh+ per year) customers to buy energy in months, quarters or seasons, in and out of sequence. Customers have access to a dedicated product team as well as a trading desk for base-load and peak purchases. This gives added flexibility to the supplier – while also offering benefit to the largest customers, by providing more freedom, control and price transparency to that customer's energy purchasing.

- **STOR** – some suppliers are exploring possibilities in STOR and wish to understand STOR better.

- **Triad Management** – for most 100kW-plus half-hourly settled I&C customers - TNUOS Charges (Transmission Network Use of System) are a direct pass-through into end-bills. Suppliers therefore provide TRIAD warnings to their half-hourly customers – but chiefly as a 'customer service' – and without direct cost-saving to the suppliers themselves. National Grid estimate annual TRIAD demand reduction at around 0.5 – 1 GW[21]. TRIAD management is likely to include a high component of on-site generation – but not known how much. Interestingly, in trying to avoid the three TRIAD half-hours at winter evening peak, I&C half-hourly customers now make so many attempts at avoidance by reducing their load, that the shape of winter half-hour system peak has shown some change - in turn making TRIAD prediction harder.

- **Triad Management** – run distributed generation at a TRIAD period, to reduce TRIAD liability of the generator and associated client site (where applicable) e.g. CCGT associated to local distribution zone or CHP attached to industry.

- **Transmission constraint management** - suppliers keen to understand more on how to participate.

[21] See Annex 3 for more detail on explanation of the annual £/kW network Demand charge payable by licensed suppliers to National Grid via TNUoS charges - Transmission Network Use of System Charges. TNUOS charges for a supplier's largest half-hourly settled customers are calculated by taking the average three half-hours (10 days apart) of highest system winter peak demand – a TRIAD. The aim of TRIAD charging is to incentivise suppliers – and in effect their largest customers - to curtail their maximum load at annual winter peak, to enable deferred transmission network re-inforcement.

Suppliers – DSR Value

27. The wholesale component of the end-price of electricity is currently somewhere between 50-60% of a customer's bill. In theory, potential long-term avoided-cost value from DSR should therefore be available to suppliers from :

- Avoided capital costs – OCGT, CCGT.
- Avoided / and or better management and contracting of fuel procurement (wholesale markets, balancing).
- Avoided network charges – Transmission, Distribution.

28. However, suppliers tended to view potential avoided-cost values today as currently quite limited. Both wholesale and system balancing costs may have to be considerably higher, for any worthwhile potential avoided-cost value to be available to share with individual consumers at the household level. For example, a total potential avoided supplier cost from peak-shifting from DSR might still only translate at the level of annual savings to an individual customer as a very small amount (e.g. possibly a few pounds per customer p.a.)[22].

29. In addition, suppliers with whom we spoke stressed that delivery of a reliable electricity supply was paramount. From a supplier perspective today, this is more readily assured through generation than by DSR. On sound business grounds, suppliers as of today do not view the two alternatives as equivalent.

30. In addition, for suppliers, lower distribution charges which may result from deferred or avoided investment is a delayed benefit and at one-remove – including any eventual value associated with deferred / avoided network investment from DSR – perhaps more so, given that many suppliers no longer own network assets. From a supplier perspective, distribution charges are very largely a non-controllable cost, transferred to customers. Suppliers will pass through distribution charges to I&C customers : the ToU element in the CDCM (Common Distribution Charging Methodology) may be explicit / visible to I&C customers - or not. For household and smaller business customers, the distribution charge is neither visible nor transparent.

[22] Domestic and SME tariff development for the Customer-Led Network Revolution. A Report prepared for Northern Powergrid. Frontier Economics. May 2012. For example, see p.82

Suppliers – Key Issues in Discussion

31. Aside from the examples noted above (and in Annex 1), even where suppliers could in principle identify potential value from encouraging DSR / load-shifting activity by their customers, on the whole they struggled to see an immediate pathway to realising that prospective value for their business – other than via developing energy services activities. From a supplier perspective – both integrated and independent - there are a number of potential 'market failures' to address before DSR value can more readily be realised. These are discussed in Section III.

Distribution Networks - Interest in DSR

DNOs - Main Reasons for DSR.

32. GB Distribution Networks are actively exploring a variety of customer incentives and approaches to demand response – both for fault management and for peak-avoidance – either working directly with customers and / or through aggregators – including via LCNF (Low Carbon Network Fund) - to defer or avoid peak-related capital expenditure for network re-inforcement - which the wide-scale connection of PV, heat pumps and electric vehicles may otherwise require.

33. For DNOs three basic aims were indicated for DSR :

- **Capital expenditure savings** – to improve potential for deferred or avoided capital expenditure at different voltage levels – while planning, building and maintaining the resilience of the distribution network to required industry engineering security standards[23].

- **Improved Pre-Fault and Post-Fault Management** – at higher voltage, to defer or avoid capital expenditure and reduce outage times.

- **Automated Load-Management** – eventual development of automated load-management as a tool – especially to manage / balance Renewables and new sources of load (potentially all voltages – but mostly at low voltage).

34. **Location** - for the distribution networks, the benefit and development of DSR is likely to be very location-specific.

35. In discussion with DNOs, DSR was seen to offer the following potential :

- At low voltages, a systematic day-in-day out daily load shift and / or demand reduction - over DNO winter evening peak (16.00h to 19.00h) – to release potential value from deferred or avoided network capital expenditure. At lowest voltages,

[23] Network is planned, built and operated to Engineering Standards (P2/6). These standards vary at different Demand Groups on the network, according to customer density e.g.Group A, B, C. – but at each level, the network is designed to resolve 'worst case fault' for that given level of Network. The network standard for a low-density customer group such as Group A is unsecured / has no redundancy – but is nonetheless designed to withstand a certain statistical risk of overload ; Group B – N-1:to withstand a single circuit fault. Group C – N-2. To withstand a double circuit fault (i.e. some parts of HV & EV network).

where the distribution security standards require no 'redundancy'[24] , consistent day-in-day-out DSR could offer potential value in deferred or avoided investment while maintaining a given level of resilience / supply security.

- Reduced or shifted demand at lowest voltage would 'trickle upwards' – because it should also create in equivalent 'head-room' at higher voltage levels too.

- At higher distribution voltages : where the network security standards require some inbuilt redundancy, DSR offers additional 'insurance value' – and thereby can allow deferred or avoided capex while safeguarding against relatively rare one-off events – e.g. pre-fault handling, fault handling, extreme weather.

36. Four potential DNO approaches to realising value from avoided network investment were**:**

- **Non-firm connection agreements.** Company and customer share the up-front benefit of reduced reinforcement for a new or upgraded connection**.** Most likely to be offered for new and / or upgraded connections for renewables and / or a new development site. (Possibly less applicable in the near-term for existing small loads).

- **'On-demand' customer response.** An 'insurance' arrangement on higher voltage networks (i.e. networks with some redundancy) – by matching contracted I&C customer DSR to an occasional loss (probably seldom) of an incoming circuit**.**

- **Day-in-day-out tariff-like response.** A consistent change in behaviour designed to reduce electricity consumption at peak - and therefore reduce the baseline peak demand against which the low voltage network must be designed for security standard compliance at that location. This type of response could be very beneficial at low-voltage networks designed without redundancy, but also, potentially, offers a value by way of increased headroom to the higher voltage network too. Likely to prove most effective when aligned with price signals of other market actors – e.g. a supplier Time of Use tariff.

- **Electricity demand reduction.** Applicable both to commercial loads at higher voltages e.g. commercial lighting – and household load at lower voltage. An *overall* reduction in electricity consumption could both reduce customers' bills - and may, in some situations, help to defer or avoid network investment**.**

[24] i.e. for low density customer groups e.g. Group A

37. Potential avoided-cost savings for DNOs from the kind of measures outlined above might be realised in distribution charges as (1) lower connection charges (payable by large customers) and / or (2) as a long-run downward pressure on DUOS charges payable by suppliers (and so by customers)).

38. Economy 7 excepted, current DSR procured today by DNOs amounts to a few tens of MW.

39. Examples of DNO DSR activity are in Annex 1 and included :

- **Non-Firm Connection Agreements** – as noted above.

- **Contracts for Avoided Network Reinforcement** – through aggregated I&C Load – either for pre-fault management – and /or to avoid primary substation re-inforcement.

- **Economy 7 Load Switching** – still substantial Economy 7 tele-switched loads (perhaps still ~500-1000 MW tele-switched winter heating load). This can bring a location-specific benefit for network constraint management and so for avoided network re-inforcement.

- **Common Distribution Charging Methodology** – since April 2010, distribution charges payable by half-hourly settled customers, have incorporated a seasonal three-part time-of-day element (STOD), to provide an incentive for winter weekday evening peak-avoidance – which suppliers mostly pass-through directly [25].

[25] Red, Amber, Green periods.

For EHV directly-connected customers, there is a high 'super-peak' charge at winter evening peak as a DSR incentive. All half-hourly I&C customers (117,000) also have a separate capacity-related element in their DUOS charges.

For larger Load Profile 5-8 customers (~166,000) – some of whom who may be half-hourly metered but not half-hourly settled - there is a 2-part day-time and lower night-time pence/kWh unit charge. There is also a fixed pence/day/ customer charge to reflect fixed costs of supply – and a capacity-related element is factored into the calculation.

For the vast majority (29 million) LP 1-4 customers, there is a pence/kWh unit charge (plus a night-rate for Economy 7 & off-peak customers). As for LP 5-8 customers, there is also a fixed pence/day/ customer fixed charge (in effect a standing charge) to reflect fixed costs of supply – and a capacity-related element is factored into the calculation.

- **LCNF / Other Trials** – CLNR (Customer Led Network Revolution) ; Low Carbon London ; SPEN ; ENW.

Distribution Networks – Potential DSR Value

40. DPCR5, re-inforced by RIIO, sought to neutralise DNO incentives as between capital investment and operational expenditure by adopting a new 'totex' approach (total expenditure). This has allowed capital and operating cost options to be considered as alternatives. In turn, this means that together with new network investment, DNOs are also looking to develop a mix of new responses such as DSR and storage to support cost-efficient network security, in the face of uncertain volumes and locations of new loads connecting (EVs, Heat Pumps, micro-generation).

41. Distribution Use of System Charges (DUOS) – currently represent ~18% of an average household end electricity bill. In principle, a total 10% reduction in DUOS charges from 'avoided cost' actions (e.g. deferred or avoided investment) would therefore potentially today give ~2% benefit in terms of an average end-bill (location specific benefits could be more material).

42. At present loads, 10-15 % may be at the high-end of expectation for customer load-shifting – unless and until there is more shiftable load on the networks. Associated value of DSR to the networks will therefore depend on the rate of future load-growth. But, in very broad terms, one suggestion was that a firm 10% load-shift at a particular location could possibly lead to a 20-year deferral for network investment.

43. The benchmark for establishing a value / price payable to a customer for DSR is on an avoided-cost basis. For DNOs, this is against the long-run cost of investment in the network (LRIC). So, the price offered by a network to a customer for DSR should not exceed the cost of new network investment as indicated by LRIC[26].

[26] LRIC applies at EHV. At HV/LV, calculation of the relevant yardstick is via the Distribution Reinforcement Model.

Example – If LRIC of investing in 1 MW of new network capacity is, say, £50k/MW/pa (average) then :

- any DSR bid <£50k/MW/pa would be accepted.
- Any DSR bid >£50k/MW/pa would not be accepted, because it would be more cost-effective to invest in the network.

44. One suggestion was that in the long-run, it may be feasible to run an auction for up to several GW of DSR capacity in a region or location - the reserve price being LRIC.

45. We have not identified much by way of published data on possible avoided-cost values from DSR in the distribution networks[27]. Any such values are likely to vary significantly with distribution network voltage, location and loading. In discussion, some indications suggest a possible range *for an average annual value* of potential avoided distribution network capital expenditure from DSR of £40 - £60/kW/pa – so possibly £40-60,000 / MW/pa.

46. Moreover, a single basic £/kW pa figure for the potential avoided-cost value from DSR does not necessarily adequately reflect potential cost-differences between low and high voltage networks. Nor, for example : rural, urban, or otherwise very constrained locations.

47. DNOs stressed the significant investment cost-differences between different network areas and types. For example : the costs of permits to dig and a general premium on space, makes for very different costs in re-inforcement and on-going operational costs in dense urban areas; basement substations in cities, where significant expansion may not be possible without purchase of, and relocation to, a new site etc. Also, in such situations, equipment specifications may also widely differ – to reflect different cooling - or size – requirements. All such factors may impact costs differently.

48. There are also different triggers for investment at different network locations. Assets which become the initial 'pinch-point' both impact the nature of re-inforcement required - and also - the available alternatives. For example, in some network areas, it may be the thermal limits of assets that cause the pinch-point. In such cases, technical solutions such as dynamic ratings (i.e. better visibility and management of the exact

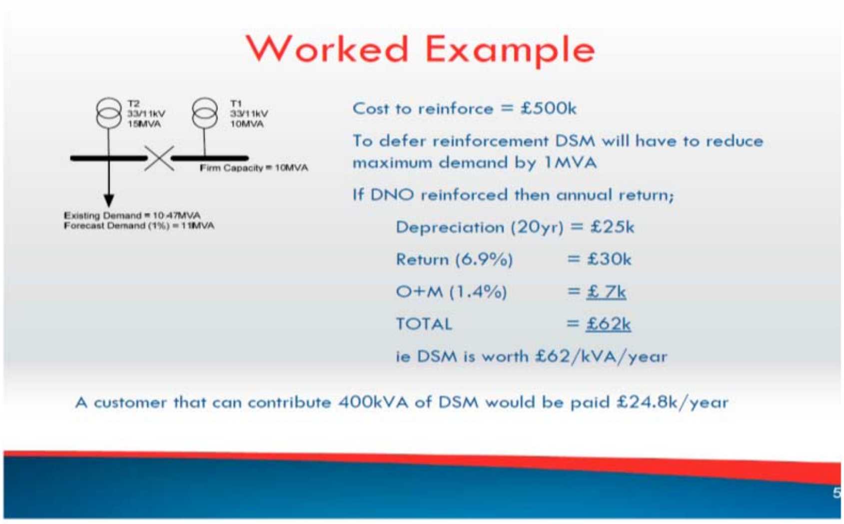
[27] Two useful papers are : (1) At a generic level - the evaluation framework and model produced for the DECC / Ofgem Smart Grid's Forum 'A framework for the evaluation of smart grids. A report prepared for Ofgem'. March 2012. Frontier Economics and EA Technology. (2) Domestic and SME tariff development for the Customer-Led Network Revolution. A Report prepared for Northern Powergrid. Frontier Economics. May 2012.

headroom available) - or advanced cooling - may be short-term lower cost options open to the DNO. In other instances, such as a voltage constraint, or a transformer which is at its thermal rating, the only available option might be replacement / upgrade of the asset – unless DSR can be practically deployed.

49. Two helpful examples to illustrate the nature of DNO choices relating to network reinforcement and avoided investment potential from DSR (or alternatives), are as follows.

50. **Example 1 : ENW Worked Example.** (Electricity North West). In this example, network reinforcement at a particular location has a potential cost of £500k – but could be deferred (or avoided) by securing 1 MW of DSR. The calculation indicates that a maximum avoided-cost payment of £62/kW/pa could be offered to a customer (i.e. £62,000/MW/ pa). So, a large I&C customer able to offer 400 kW of DSR, could earn a total of £28,400 pa for curtailing their load – perhaps for only a very few interruptible events each year – enabling transformer re-inforcement at that location to be deferred, and which would otherwise be needed to cope with expected load-growth.

ENW Worked Example



Source – ENW Slide. IEA DSM Workshop. Chester. October 2009.

51. In this example, depreciation was calculated over 20-years. However, if for any reason, depreciation was calculated over a longer time-period to align with physical asset-lives

- e.g. 40-45 years - this may reduce the annualised cost estimated for avoided network re-inforcement – which in turn would be likely to reduce the annual sum available to offer customers in return for their DSR.

52. **Example 2 : A DNO substation site.** A small variation in the firm capacity of the overhead lines feeding a substation site, means that reinforcement will soon be needed. Addition of a third line, together with a third transformer, is expected to cost around £9m (the line routes are relatively long). This work would increase the capacity of the site from around 35MVA to 70MVA. This would significantly exceed current requirements - but would also cover future requirements for a significant period. Alternatively, if peak demand at this site could be reduced by 5MW for several hours during cold winter days on a firm basis – either by DSR or by other means - then there would be potential to defer this reinforcement. As per the illustration above, the benefits or avoided cost-value are then driven by the period of deferral. This in itself is very dependent on growth in background demand, uptake of low-carbon technology, and wider economic factors.

Distribution Networks – Issues in Discussion

Distribution Charges – and Current Incentives for DSR and Demand Reduction

53. In discussion, a number of complex and detailed issues were touched on regarding current arrangements for distribution charges – both DUOS (distribution use of system) and Connection charges - and their respective roles in shaping future development of greater DSR. Some of these issues are being considered by Ofgem for ED1. We will return to charging issues in Paper 7.

54. **DUOS Seasonal Time-of-Day charges for Large I&C Customers** - DNOs generally took the view that seasonal TOD price-signals introduced into DUOS charges for I&C customers (many connected at EHV / HV (but not all)) from April 2010 were a helpful step in avoiding peak-time use – albeit not perfect. In particular, super-red time bands introduced at EHV from April 2011 were proving a strong signal[28]. For some large customers, the ToD charges are not necessarily passed through in a direct and visible way by their supplier. From a DNO perspective, the network-wide ToD periods are

[28] Super-red time bands introduced via the EHV Distribution Charging Methodology (EDCM) from April 2011 for EHV directly connected half-hourly settled customers. Super-red time bands are chargeable at winter weekday evening-peak across all DNO areas – except London where super-red time bands apply during winter evening peak hours (16.00-19.00h Nov – Feb) – and summer months (11.00-14.00h June-August).

sometimes ill-matched to local peaks. Some DNOs saw it as helpful to seek to align ToD DUOS charges with supplier TOU retail tariffs – so as to consolidate and convey a stronger peak-price signal to customers.

55. With the exception of these charges to the largest half-hourly settled I&C customers[29] - who are mostly (but not all) connected to the EHV and HV networks - the costs to the vast majority of non-half hourly settled customers of providing, operating and maintaining the distribution networks - and the attendant benefits of a largely secure electricity supply - are recovered via socialised distribution charges[30]. This enables continued simplicity for suppliers – and general fairness from a customer perspective – but in the long-run arguably may dull the scope to create incentives and develop price signals which might encourage more DSR or demand reduction. We touch on the topic of greater cost-reflectivity in charges in section III.

56. Some areas identified in discussion, where socialised distribution charges may, for the future, fail to shape effective DSR responses, were as follows.

- **Value of DSR to an individual non-half hourly customer** : any cost-savings from DSR are socialised (averaged) across all suppliers (and their customers). So, at the individual customer level, there is little individual value / benefit from avoided distribution charges for a supplier to share.

- **Location-specific value of DSR** – DUOS charges for both half-hourly and non-half-hourly customers are indifferent to any potential locational benefits of DSR. This is because DUOS charges do not incorporate an explicit locational signal. Importantly, this means that the price-message embodied in distribution charges to suppliers (and so to their customers) signals that any avoided kW has an *equal* value - *regardless of where on the distribution network that kW is avoided.* There is therefore currently no price message to suppliers - and therefore to their customers – as to *whereabouts* on a network the greatest avoided-cost value from DSR may sit in practice. **It is nevertheless currently open to a DNO to share cost-savings achieved from DSR at a particular location - with a particular customer or customer-group. This can be reflected in a separate and direct arrangement with the customer – outside of DUOS charging arrangements.**

[29] 117,000 of 29 million customers in September 2011.

[30] But which vary in terms of fixed charges and usage charges according to customer Load Profile 1-8.

- **Higher relative value of an avoided kW at Low Voltage (true for both DSR and for Demand Reduction)** : DNO's explained that, in principle, an avoided kW at low voltage offers more relative value in £/kW avoided, than at HV or EHV[31]. Therefore, in theory, a kW avoided at peak on the LV network (or saved altogether from demand reduction) potentially may offer greater value than an avoided kW on the HV or EV networks (or, indeed, an avoided kW on the transmission network). From April 2010, detailed adjustments to cost-allocations in DUOS charges recognised relatively higher costs at lower voltages[32]. Nevertheless, the universal p/kWh charge[33] - seems to offer a somewhat dull signal to both suppliers (and ultimately to their customers) of the potential for cost-savings associated with an avoided kW at low-voltage.

- **DUOS charges and increased load** : for the vast majority of non half-hourly electricity customers, DUOS charges are usage-related – but are not explicitly load-related. DUOS is a p/kWh charge to suppliers – i.e. a total usage / energy charge per customer. For non-half hourly customers, DUOS therefore does not incorporate an explicit p/kW charge - designed to address (or curtail) maximum demand[34]. This results in an absence of price-signal in current DUOS charges about the extra network costs associated with additional and (relatively) major new load connecting at LV – eg electric vehicles, heat pumps.

[31] Because the cost per kW rises as voltage falls (i.e. on the lower voltage network) ; and, also, because reducing demand at LV trickles upwards to reduce demand at higher voltage levels too (because redundancy increases).

[32] Charging adjustments which reallocated cost-recovery of certain costs from the higher voltage to the lower voltage networks

[33] Paid by suppliers in their DUOS charges for the 29 million LP 1-8 customers mainly connected at low voltage. p/kWh charge varies by Load Profile. DUOS charge is a relatively small element in the end-bill – and anyway not visible to the customer at an individual-level.

[34] The calculation of the fixed charge payable by each non-half hourly customer (pence/customer/day), incorporates an element relating to capacity – but this is neither material nor transparent to suppliers - or to their customers. Separately, connection charging arrangements for non-half hourly customers, relating to significant new load or to an upgrade (e.g. an industrial estate, housing development) - would reflect the asset-related costs of a given 'maximum required capacity'.

Half-hourly settled customers - do have a separate and transparent capacity element in their DUOS charges – plus a penalty charge if this is exceeded. Separately, connection charges for these larger customers will also reflect their 'maximum required capacity'.

- **Connection charges** : 'asset-related' connection costs of 'major' new load – As noted, DNOs already offer Non-Firm Connection Agreements at all voltages for large new loads which are either connecting – or upgrading. This can result in lower connection charges (due to avoiding construction of new connection-related assets) and also lower DUOS charges[35] . However, smaller existing customers, already connected at low-voltage, do not currently face the prospect of additional connection charges for connecting new load, such as EVs and Heat Pumps, although such loads may prove fairly significant in terms of the capacity of a local LV network.

Distribution Networks – Other Issues in Discussion

57. Additional issues raised in discussion by DNOs were as follows :

- **Automated load and load-management tariffs** - From a network perspective, with a heavily renewable system in the future, DNOs may wish to have more direct load-control than now, similar to today's Economy 7 tele-switch capability. Some DNOs expressed interest in possible load-management tariffs – especially at low voltage – seeing this as a potentially more effective direct intervention than a TOU signal in DUOS charges[36] . From a network point of view, direct automated control of household load at low voltage could potentially allow deferred or avoided investment while assuring network security. From both a network and customer security of supply point of view – distribution load-management tariffs may therefore be worth exploring. Appropriate smart meter capability / functionality may be needed i.e. DNOs favour a capability for direct control of EVs, HPs and micro-generation to enable individual customers to 'opt-in' at some later stage to possible load management tariffs.

- **The P2/6 Regulations for assessing network investment** - to ensure supply security are currently somewhat more geared to take account of certain kinds of distributed

[35] Annex 4. A non-firm customer - opts for a lower up-front connection charge and lower on-going distribution use of system charges. In return, their connection assets are designed, built and operated to a level which does not guarantee output / load at their requested 'required capacity' at all times. For example, if thermal limits are approached at that network location, then the non-firm customer's load (or generation) could be curtailed.

[36] Currently anyway only applied to I&C customers, many of whom are connected to the HV, EHV networks

generation / back-up plant as a potential avoided-cost solution - than towards DSR[37]. In due course, such historic regulations may need review to bring DSR onto a more equal footing.

- **At higher voltage (EHV / HV) – DNOs aim to make the network smarter -** including seeking DSR from I&C customers for fault 'insurance'. This seemed to DNOs to offer the most practical opportunity for avoided investment - even if not necessarily the greatest avoided-cost value (because, as noted, on average, an avoided kW at HV implies a lower £/kW saving than at LV).

- **At lower voltages -** as more electric vehicle and heat pump load connects, greatest avoided-cost value should come (1) from outright electricity demand reduction of other load (i.e. not shifting) and then (2) encouraging customers (mostly households) to shift their *new* load (EVs, heat-pumps) consistently day-in-day-out at evening peak (commonly 16.00h to 20.00h or later for distribution networks).

- **Nevertheless from a DNO perspective, it seemed more realistic to invest in the network at LV to ensure supply security** – even though it may be where most avoided-cost potential from DSR may lie – rather than rely for network security on household customer response (unless automated). Scope may exist to involve communities in load-shifting / load-curtailing – for example, to encourage co-operation, e.g. via non-firm connection agreements etc. This would differ from today's approach to network security, which at lowest voltages, presently depends on the local 'load-diversity' of many different customers.

- **Aligning DSR hierarchy across the electricity system** - it was felt that it would eventually be feasible to align objectives of :

    - DSR 'insurance' policies by DNOs with I&C customers at higher voltage – may eventually be capable of closer alignment than presently, with system operator STOR requirements.

[37] Assessments under ENA Network Engineering Regulations (P2/6) for network supply security compliance enable generation / back-up plant to be taken into account because the provision for generation in P2/6 is weighted to reflect the uncertain/reduced load factor. However, despite this provision, on a practical level the contribution from distributed generation is almost always excluded in the design and planning for security of supply compliance - due to uncertainty around actual contribution and latent demand. At the smaller, micro-generation levels it is even more challenging for a DNO to know about the real level of generation in the network area and so again contributions to security compliance are not generally taken into account (i.e. smaller-scale generation connected under G83 - notified post-installation – rather than larger G59-compliant connections).

- DNO winter peak avoidance – given that the constraints of a distribution network are closely aligned to those of other market actors e.g. align with price signals of other market actors' (e.g. for wholesale energy, TRIADs).

- **Voltage Management** – Voltage is currently managed at the national electricity system level by the system operator via the reactive power market. At distribution levels, there may be technical and commercial potential to improve voltage management and a number of issues were raised in discussion – see Annex 5.

  - On the distribution networks, especially at low voltage, there is relatively low-penetration of voltage monitoring. This is a growing challenge for the distribution networks, exacerbated by new PV connections.

  - On the local low voltage distribution network, PV increases voltage on the network when exporting. This brings new issues for DNOs in terms of voltage management – including significant unpredictability / voltage swings. DNOs are required to manage voltage within prescribed (statutory) limits – and (in principle at least) could possibly face potential claims for consequential loss (e.g. for equipment failure or damage) from excursions outside the statutory voltage limits. But, with new PV clusters, for reasons beyond their control, DNOs are finding local voltage increasingly hard to manage. In addition, inverters within PV installations may disconnect an array if voltage exceeds, say, 260 volts to protect the network. Questions therefore arise as to how far a network must be re-inforced to meet maximum PV output.

  - Commercial issues for improved voltage management at distribution level need to be better understood.

  - Voltage optimisation equipment – aim is to manage voltage within customer premises (ie customer side of meter) and can reduce power requirement within buildings. Views differ on likely savings, but some suggestions are that voltage optimisation can save 10-15% on a customer end-bill. Equipment paybacks may be high.

Aggregator Interest in DSR

58. There is a long history of third-parties aggregating I&C load to offer DSR services to National Grid Ancillary Services.

59. More recently, aggregators have entered the GB market with a business model geared initially largely to providing Balancing Services to National Grid. Latterly, aggregators are also providing DSR services to some DNOs too. Currently there are around a dozen aggregators / agents active in the GB electricity market.

60. Generally, some upfront investment is required : hardware ; software ; engineering cost ; transaction costs of aggregation ; sales and marketing – including prospective customer 'audit'. A smart meter capable of recording on a one minute basis is a requirement for STOR. The aggregator may meet these up-front costs in full, presumably against the future revenue stream to be shared with the customer.

61. Main focus is either >100kW customers – or multi-site customers. A single-site 100kW customer may earn ~£2-3k pa ; a far larger multi-site customer could potentially earn >£1-2 million pa (assume for being called up to 50-80 times per year in STOR).

62. Aggregators may be able to offer the DSR services which they have contracted from customers to *both* National Grid and to Distribution Networks – provided they are able to manage the risk of non-delivery. In principle, customers should be indifferent as to which actors in the market they provide their load-shifting service.

Customer 'Fit'

63. From a market actor viewpoint, technical requirements needed from a DSR provider arguably fall into two very broad categories :

- **Speed of response but of comparatively short duration** : largely required by the system operator for frequency response and fast reserve.

- **A more sustained response – but with longer notice periods and scope to take longer to deliver** : STOR ; TRIADs ; DNO EV & HV fault management ; DNO LV peak avoidance – and for the future – capacity management.

64. Arguably, from a market actor viewpoint, the need for firmness of response and to contract some way ahead, may push towards generation solutions rather than DSR.

65. From a DSR provider perspective, the service which they can offer a market actor requires both 'technical' fit – as well as commercial fit. This is true at all levels of the system. For both customer and market actor, this match includes :

- Technical : speed and duration of response ; load shape ; location.
- Commercial : contract duration ; consequences of 'non-delivery'.

66. Examples of such customer 'fit' are described in Annex 1. These include :

- A specific customer load-profile at a particular location to mitigate a particular network (or system) problem.
- Aggregated load – for Frequency; STOR. Avoided primary transformer reinforcement.
- Single large I&C loads - for peak avoidance in 'extreme' / relatively one-off conditions – e.g. TRIADs.
- Many small individual automated loads at scale – day-in-day out for a system-wide or a local network impact (Economy 7).

67. Which customers can access the DSR value / cost-savings available today ?

- **Industrial & Commercial load** – Sector most likely to capture available DSR value today - selling into Balancing Services via aggregation (especially from back-up plant). Also able to offer DNOs 'on-demand / ad-hoc' customer insurance for fault response at EHV/HV. Half-hourly settled Industry customers are anyway to some extent already doing TRIAD management.
- **Households – Economy 7** : ~500 –1000 MW of tele-switched load. ~250 MW teleswitch customers currently provide Fast Reserve into Balancing Services. Today,

no other obvious equivalent source of readily switchable household load - until EVs and (potentially) Heat.

68. In addition, as at today, Brattle also suggested that:

- Domestic load is likely to be the main contributor to shiftable load – regardless of whether winter or summer. Also, that shiftable domestic load may increase towards 19.00h.

- At winter evening weekday peak, the bulk of potentially shiftable load today comes from on-peak electric heating - in both the services and household sectors.

- There are sizeable morning peaks with potentially significant shiftable load - both in winter and in summer.

69. Key attributes for a good DSR 'match' for customers and market actors are therefore :

Customer

- Willingness / ability to shift or curtail load – for price on offer.
- Load-shape – sufficient flexibility available on the specified day and time – i.e. customer able to offer the avoided load-shape needed by that market actor.
- Ability / preparedness to meet market actor (or aggregator) requirements for : notice ; speed ; duration of response.

Market Actor

- Sufficient avoided-cost value available / on offer to incentivise customer participate in a DSR scheme.
- Location – many market actors need load curtailment and shifting at specific locations. This will be increasingly true. Customers may be willing – but sited in the wrong location – including for Balancing Services.

70. For the future, if suitable customers do not come forward to participate in DSR schemes – either at scale - or in the right locations - then market actors seeking DSR to avoid high capital or operating costs may need to actively pursue :

- Aggregation of very many small diverse loads (e.g. multi-site retail outlets, households) – either system wide – or at a particular location – to deliver by aggregation / automation both diversity and specific load-shape / and or particular technical characteristics (speed of response, duration etc.).

- Self-balancing - e.g. PV, wind - with thermal storage. Potentially at household and / or community level.

71. Strawman 1 overleaf attempts an overview of which DSR services customers may be able to provide today to different market actors. It is very much an initial view – intended for discussion.

Strawman 1 – Which customers can access the DSR-Value which is available today ?

	Balancing services			TRIAD	DNO		Wholesale
	Frequency response	Fast Reserve	STOR		Peak avoidance	Fault insurance	
Industry (HH metered customers) – relatively bespoke load profile	✓	✓ ?	✓	✓	✓ ?	✓ not widespread, some trials ongoing	✓
Commercial (Load Profiles 5-8) – flat load profile, but sector seemingly likely to capture available DSR value today	✓? Some trials ongoing (retailer HVAC trials)	?	✓ Through aggregators	X no potential as not HH metered	?	?	X
Household (Load Profiles 1-4) – Economy 7 – scope for automatic switched load.	X	✓ teleswitch customers	X	X - ditto	✓ teleswitch customers	X	X

II Potential Avoided-Cost Value from DSR for Market Actors

Understanding DSR Values in the Electricity Market

72. The basis which under-pins this paper is that DSR may allow market actors to realise some new cost-savings in the electricity market – ie to realise the potential avoided-costs – either of capital investment and / or of energy. This in turn should release cost-savings – and / or new revenue streams – to be shared with / passed to customers as a 'reward' / incentive to shift their load.

73. Ultimately, the aim is to understand in very basic terms - from a customer perspective - in offering DSR services to market actors, which part of the electricity market might reward which customers most (assuming good technical 'fit'). For example, to understand more clearly :

- How much money can customers and consumers save from DSR in practice ?
- Can most be saved by moving load at evening peak (17.00-19.00h) ? Or at other times of day ?
- Which customer groups stand to save most money from DSR : I&C ? Households?
- When might worthwhile cost-savings be available to customers – Today ? 2020 ? 2030 ? And for which customers ?
- How high would retail prices need to go – i.e. higher system balancing costs ; higher wholesale energy prices – to spur customers to seek-out DSR solutions ?

74. We had aimed to summarise at a very high level what possible cost-savings from deferred or avoided capital investment from DSR may be available to market actors today – and therefore potentially what value may be available for market actors to share with their customers. However, possible cost-savings from DSR from potential avoided-investment across the GB electricity system today, were not very readily calculated in practice.

75. There are two current sources of information on avoided-cost value from DSR: modelling exercises, some of which look out well-beyond 2030 and are therefore inevitably rather high-level [38] ; plus, somewhat patchy information on DSR values / prices available in the market today.

[38] For example : 'Assessment of DSR price signals'. Paper for Electricity North West and National Grid. Poyry Consulting. December 2011; 'Benefits of Advanced Smart Metering for Demand Response based Control of Distribution Networks'. Summary Report. Centre for Sustainable Electricity and Distributed Generation. Imperial College & Energy Networks Association. April 2010 ; 'A Framework for the Evaluation of Smart

76. There are two basic sources of avoided cost-saving from DSR :

- **Avoided-Costs of Fixed Infrastructure** - plant and equipment. Mostly needed to meet *maximum demand on the system / system peaks* (but not only) :
    - Generating plant (peak, flexible).
    - Transmission and distribution networks – connection assets (transformers etc); wires and cables.
- **Avoided-Costs of Energy** – Balancing services ; wholesale electricity markets.

77. Some examples of possible price 'benchmarks' to indicate avoided-costs / savings in today's market from DSR are as follows :

- **Firm Frequency Response 2011-12** – Indicative payments : £50-60/kW/pa – split between a tendered fee for : availability ; holding ; and utilisation.
- **Fast Reserve** (2009 average) - £50k/MW/pa – splits £44k/MW/pa availability payment ; £6k/MW/pa usage payment. (BM-generators - £/MWh as per BM bid-offer prices).
- **STOR 2011-12** average bidder offers - £8/MWh availability payment ; £225/MWh usage payment. (& lower than 2010-11).
- **TRIADs** – TNUOS demand charges : £10.74/kW/pa (north of Scotland) to £31.17/kW/pa (south-west).
- **Distribution Network** – avoided reinforcement costs £40-60/kW/pa (SF 'guesstimate').
- **Wholesale Power Price** – average 2011 - ~£40/MWh

78. However, such prices offer only a very incomplete picture. Comparison between the different 'service requirements' for DSR – in effect between the different markets in which DSR can play - is not straightforward.

79. To develop a better understanding of (1) the possible cost-savings from DSR against alternatives through the full electricity value chain – and therefore (2) any potential cost-savings available to customers from their DSR – a more systematic evaluation will be needed than has been feasible here.

80. Such an evaluation would first require a better understanding of the avoided-costs which DSR could bring in the GB electricity market, both today and in the 2020's,

Grids. A report prepared for Ofgem'. Frontier Economics and EA Technology. March 2012. 'Domestic and SME tariff development for the Customer-Led Network Revolution'. A Report prepared for Northern Powergrid. Frontier Economics. May 2012.

through avoided peak-related infrastructure (£/kW/pa for networks, generation), and avoided costs of energy ((£/kWh peak-related and wholesale)), including interaction with half-hourly Balancing prices. DSR solutions deliverable below these bench-marks of avoided-industry costs could be expected to create savings for customers and consumers. Any such evaluation would then help to point towards those parts of the electricity market in which (1) DSR is likely to be cost-efficient, including in what time-frame – and (2) in which parts of the electricity value chain, DSR may offer most value to market actors - and so offer greatest potential cost-savings to customers - given that the industry's costs will reflect into retail prices.

81. Any detailed assessment of potential DSR values and possible cost-savings for customers would need to take into account the fact that :

- Different parts of the electricity market require significantly different DSR 'products';

- Not all customers can offer the specific DSR characteristics needed by different market actors due to : the nature of their own electricity use ; their shiftable load ; its availability ; and, their location. Some customers may therefore be unable to offer DSR on the basis sought by market actors. Equally, some other customers may be able to command something of a premium for a particular DSR service which they are able to offer.

82. Available DSR savings for customers will therefore be shaped in practice by their ability (or the ability of aggregators) to offer some relatively narrowly-defined technical services into different parts of the electricity market - at a cost below alternatives. So, DSR would need to be able to offer defined technical characteristics – e.g speed of response, volume, endurance[39] – at a cost below that of providing the same service via other means e.g. BM Units, non-BM Units (incl distributed generation), storage, interconnection - or investing in / reinforcing a network[40]. At a more detailed practical

[39] So, whether DSR service is required : almost instantly (Frequency) ; at speed and at volume (Fast Reserve) ; week-in-week-out at certain times of day, changing seasonally (STOR – 20 to 80 hours p.a.); for only a very few 'critical' events each year – and for a very short time-period (TRIADs – 3 half-hours p.a.) ; a sustained-period each day, for up to several weeks or more at winter peak (Capacity) ; a sustained period at any time of year and without notice – but seldom called (DNO fault insurance) ; consistent firm response at winter evening peak, all winter-long (low-voltage network peak avoidance). In addition, different values are likely to attach to being 'available' all of the time, but rarely called – or being available for only a very few, limited, largely pre-defined periods ; or being available at any time – and very likely to be called.

[40] For example, in the USA, successful DSR participation in the PJM market has been achieved precisely in this way – by defining wholesale energy market services in such a way that DSR can participate. For example : be

level, accounting treatment, such as that for asset depreciation[41], could impact on any DSR savings calculation.

83. **Locational value** - Some of today's DSR value is already location specific. In the future, much DSR is likely to have even-greater locational value. Depending on transmission constraints, this may potentially also the case for wholesale energy. Prediction of DSR-earnings for a specific 'category' or customer group of DSR providers will therefore be difficult to calculate – unless there is also a clear understanding of different locational values to a given market actor in their procurement of a particular DSR service.

84. Looking ahead to a prospective capacity market, possibly in place from 2014, and how it may interact with other markets in which DSR can have a role (so, Balancing, wholesale, TRIADs, network constraints) adds further complexity in making comparisons of potential savings from DSR from avoided investment.

85. As noted, some forms of DSR provision may command a premium over other DSR (or alternatives) – eg at a particular location : or, where DSR which can sustain a consistent firm load-shift (most likely at winter peak – but not just) over the course of an extended period.

86. **Given the complexity of these DSR value issues, and their significance in improving general understanding how GB markets in DSR may develop in the future, DECC, Ofgem and others may wish to consider how best to develop a more systematic approach and / or to develop a 'consensus' framework by which to analyse and evaluate GB DSR avoided-cost values[42].**

available up to 100 hours p.a. and up to 8 hours per event, responding within 30 minutes etc. There are also many services in the PJM market in which DSR cannot participate.

[41] i.e. depreciation of the physical assets against which the avoided-costs of DSR are to be benchmarked.

[42] Perhaps along the lines of the Smart Grids Evaluation Framework commissioned for the DECC Ofgem Smart Grids Forum. 'A framework for the evaluation of smart grids. A report prepared for Ofgem'. March 2012. Frontier Economics and EA Technology.

Where in the market might customers find most cost-savings from DSR ?

87. Value is available today in providing DSR – mainly to half-hourly settled I&C customers (and some Economy 7).

88. Balancing DSR Services:

- **Frequency and Fast Reserve** – some modest non-BMU contribution (Heating and Ventilation ; Economy 7). Considerable value (i.e. greater than STOR value) is available to non-BM DSR providers able to compete with BM-Units which already provide these services.

- **STOR (Short Term Operating Reserve)** – Aggregators are presently facilitating around one-half of non-BMU STOR requirements. They are able to share the fairly substantial values available with larger Industry / Commercial customers (> 100kW, multi-site) who are both able to meet the DSR technical requirements without impacting their main-business activity (over three-quarters of this non-BM provision is believed currently to be CHP and back-up generation).

89. Network DSR Services :

- **Transmission - TRIAD Avoidance**. Some half-hourly settled customers undertake TRIAD avoidance. Somewhere between 500-1000 MW of TRIAD avoidance occurs each year. TRIADs are in practice a relatively few half-hours in the year – in effect a 'critical peak' rebate – which if not met, customers are otherwise 'penalised' by higher annual TNUOS charges[43]. **Constraint Management** – presently no participation from non-BMU units.

- **Distribution networks –** some DSR value is available to a small group of I&C providers at specific locations who are presently able to provide firm fault 'insurance' at EHV and HV to DNOs.

90. For network management, the location-specific nature of many requirements, including for DSR, suggests that there may turn out to be a relatively small pool of possible I&C providers for that location-specific DSR. With a limited choice of DSR providers, certainty of delivery becomes very important for the networks (i.e. there is potentially less scope for 'provider-diversity' as a part of the DSR response). So, dependent on location, firm I&C providers may look for something of a premium (i.e. up to the Long

[43] See footnote 46 below on eventual possible TRIAD participation for all customer classes.

Run Investment Cost[44] at that location). Even so, albeit with limited evidence to date, there is some indication that this may not in every instance be a sufficient incentive / reward to bring forward interested I&C customers to offer DSR[45].

91. Looking ahead, greater value than today should become available in providing DSR to different parts of the electricity market :

- **Balancing services** - set to grow across all system operator requirements [46].
- **Physical peak constraints on the networks** – both Transmission and Distribution networks. Constraints expected to increase at particular locations[47].
- **Low Voltage Distribution Networks** - In the long-run, relatively higher avoided-cost values may be associated with avoided investment from DSR on the low-voltage distribution networks - than at higher distribution voltages or transmission[48].
- **Capacity** – substantial earnings may become available to DSR providers able to compete for 'long-duration' mostly peak-related services.
- **Wholesale** – in principle, value could be available to suppliers from better hedging and avoided costs in the wholesale markets from DSR. More load profiles and / or full half-hourly settlement are likely to be needed to enable suppliers to crystallise individual values to share with the customer.

92. However, both today - and looking ahead to the early 2020's - once avoided-cost value is 'shared' through the value chain amongst relevant market actors and their customers,

[44] Or equivalent value derived from Demand-Forecasting Model for HV/LV.

[45] Sustainability First – GB Electricity Demand Project. Paper 3 on Industry Customers. Also, ENW 2010 survey.

[46] National Grid. Operating the Electricity Transmission Networks in 2020. Update. June 2011.

[47] At some future point, with universal smart meters and with full half-hourly settlement, all customer classes could in principle eventually participate in TRIAD avoidance.

For example, in the US, SDG&E (San Diego Gas & Electric) has put all of its 1.2 million small business and residential customers on a peak-time rebate. A similar approach could in principle be applied to universal TRIAD avoidance. SDG&E pays $0.75/kWh to $1.25/kWh for demand reductions during critical peaks. http:/www.emeter.com/smart-grid-watch-/2012/sdge-peak-time-rebates-summers-best-kept-secret-to-save-electricity/;

[48] Para 56 above.

it remains unclear how far – or indeed when – there will be sufficient savings available to incentivise widespread DSR – especially at the household level[49].

93. One further long-run challenge raised in discussion about DSR development, was about possible longer-term impacts of increasing volumes of DSR on in the electricity system as a whole. That is, how potential DSR values / earnings may evolve over time as more DSR options come forward - and more competition develops to provide DSR services. In theory, this may create a downward pressure on available earnings. In discussion, examples were :

- **Increasing competition in STOR** - apparently already impacting potential STOR earnings.

- **Lower / less volatile prices at peak resulting from successful DSR activity**. In turn, lower price volatility may also suppress potential earnings at peak for would-be DSR providers – so creating a higher-hurdle for DSR market-entry. (Equally, suppressed earnings at peak were noted as an issue for providers of both existing and new peaking-plant (and leading to a wish for capacity payments).

- **How far a particular DSR 'service' may prove cost-competitive in practice** - especially when other factors are also taken into account (e.g. availability, firmness, long-term contractual commitment)[50].

94. **Location Specific Value -** As noted, much DSR Value will be increasingly location-specific – irrespective of whether for STOR or Network-related (i.e. Constraints, TRIADS ; DNO 'Fault Insurance'; DNO Low Voltage Peak Avoidance). Avoided-cost values will therefore be increasingly locational. In principle, this could make possible DSR earnings increasingly attractive for specific customer-groups – but this would also entail finding ways to introduce greater cost-reflection at those locations.

[49] For a detailed analysis of how DSR incentives may be incorporated into retail tariffs by 2020 see 'Domestic and SME tariff development for the Customer-Led Network Revolution. A Report Prepared for Northern Powergrid'. May 2012.

[50] For example, (arguably somewhat historic now), a National Grid 2006 paper on their '2004-05 Electricity Demand Turn-Down Trials' found : insufficient demand-side participants who wished to offer their DSR to aggregators (albeit the trial did satisfactorily establish a role for aggregation in Balancing Services); a significant mismatch between *declared* availability and *actual* availability (~50% less actual availability than declared) ; and, questionable cost-competitiveness of DSR provision when benchmarked later against Balancing Mechanism prices in the relevant half-hour periods.

95. **Other Barriers to Realising Value** - Even if sufficient value from avoided-costs of investment become available to DSR through the market – there are also other issues and barriers likely to inhibit realising the avoided-cost value from DSR that is available. These are considered in Section III.

96. Strawman 2 overleaf aims to illustrate a potential hierarchy for customers of DSR value today – it is very much intended as a straw-man for discussion.

97. Automated load of different types – and in different sectors of the economy - able to offer a good technical 'fit' to the full spectrum of market actor needs – will be fundamental in unlocking DSR value into the 2020's.

Strawman 2 – Possible hierarchy of DSR values available to customers today.

	Balancing Services			**TRIAD**	**DNO**		**Wholesale**
	Frequency Response	Fast Reserve	STOR		EHV / HV Fault Insurance	LV Peak Avoidance	
Industry (HH settled customers – relatively bespoke load-profile)	√	√?	√	√	√	X	√ Via supplier or broker
Industry in 2020's	Large Industry customers – possibly little relative change in 2020's over value already realisable today by industry customers						
Commercial (Load Profile 5-8) – flat load profile, but sector seemingly most likely to capture any further DSR value today.	√? Some HVAC trials ongoing	?	√ via aggregators	X	?	X	?
Commercial in 2020's	Commercial customers – greater potential value in 2020's via automation of Heating, Ventilation, Refrigeration and Lighting						
Household (Load Profiles 1-4) – Some Economy 7 has automatic tele-switched load (declining share).	X	√ Teleswitch customers	X	X		√ Teleswitch customers	Economy 7 customers – otherwise no
Households in 2020's	Households – greater potential value in 2020's via automation of Electric Vehicle and Heat load.						

Strawman 2 Key - Possible available DSR values today - and in 2020's

Grey – No realisable value today
Green – limited value today
Yellow – moderate value today
Orange – high value today
Brown – potentially higher value in 2020's – subject to smart meters plus improved load profiles and / or universal half-hourly settlement.
White – possibly little change over today's values by 2020's (in relative terms)

III Commercial & Other Issues for Market Actors in Realising DSR

98. Many matters were touched on in discussion by market actors as possible barriers to realising potential avoided-cost value available from DSR – either near-term or longer-term. A key and underlying question is, if savings are available today, what holds back suppliers – and / or other market actors – from offering customers more by way of DSR 'deals' / propositions today ?

99. In considering how to unlock more DSR development, we have grouped these many and diverse issues under five headings :

(1) Technical and commercial 'hierarchy' of DSR services

(2) Socialised charges, load profiles, half-hourly settlement, and cost-reflectivity

(3) Industry interactions and drivers for DSR

(4) Pre-disposition towards generation

(5) Customer loads & market actor needs – how do they fit together ?

100. We do not draw firm conclusions. We will return to many of these issues in future papers[51].

101. Market actors, Ofgem and DECC are also beginning to examine some of the issues touched on below.

[51] Policy issues in Paper 5 (July) ; Distributed Generation in Paper 6 (October) : Commercial frameworks and business models in Paper 7 (January 2013) ; Customer and Consumer issues in Paper 8 (April 2013).

(1) Technical and Commercial Hierarchy of DSR Services

102. From a largely customer stand-point, we have tried to understand - across the electricity system as a whole - where potential avoided-cost value from DSR may exist for market actors – and therefore – where cost-savings might be available to market actors to share with customers.

103. The challenge of how to establish a common technical ‘hierarchy’ together with the necessary commercial frameworks for DSR arose repeatedly in discussion. This becomes more complex still, when trying to understand how and where customers sit in the picture.

104. National Grid, DNOs, Elexon, Ofgem and ENA / ERA are each currently exploring technical and commercial interactions between different parts of the electricity market and DSR. Some LCNF projects should also help to shed light on how these different services may align in the future.

105. We asked market actors how they saw the current hierarchy of DSR provision in the market :

- **Frequency and Fast Response DSR Services for system balancing** - potentially occupy a distinct role in the market – commercially and technically. Facility for faster / more responsive load – will become increasingly important in procuring cost-efficient system operator services as the need to manage intermittency develops. Demand-side providers / customers may need particular in-built technical capabilities in their equipment (for example, in-built frequency relays).

- **STOR provision, TRIADs and Distribution Network Fault Insurance** – required characteristics potentially compatible – but from a customer perspective – may currently appear rather difficult contractually – because availability requirements of the system operator could, in some circumstances, conflict with a customer objective of avoiding their annual TNUOS charges in a TRIAD.

- **TRIAD and DNO LV Peak Avoidance** - potentially offer both a good technical and commercial ‘fit’.

- **Wholesale market** – contractual arrangements in the wholesale markets (OTC, day-ahead, forward) between generators and suppliers. Any significant DSR-type arrangements (eg Economy 7 type switching at scale) are captured in suppliers’ contracts with generators.

- **Capacity** – DSR in capacity market may deliver essentially the same technical characteristics as long-duration peak-avoidance (eg comparable to extended TRIAD provision ; extended fault insurance at distribution HV – or daily peak-avoidance at LV in the distribution networks). Commercially, values likely to tie into prices in Balancing and Wholesale markets.

106. In discussion it was suggested that, in principle, over time, many of these technical and commercial interactions may be overcome by aggregation. In effect, to achieve technical and commercial alignment across the market by aggregation - be the aggregation provided by a supplier, DNO or an aggregator.

107. In an aggregated world, the aggregator takes on the considerable financial risk of non-delivery in the electricity market of DSR services - rather than the customer directly. So, the aggregator contracts bi-laterally with a customer for their DSR service – and then ‘sells-on’ that customer’s DSR service into different parts of the electricity market. Exactly when and where that DSR may be used in the market, would depend on (1) available prices / value on offer and (2) greatest technical need in different time-scales from a reliability / security perspective (presumably also reflected in prices). Should DSR aggregation at scale become a significant feature of our electricity market, many questions arise. For example :

- **Aggregator balance sheet** - aggregators will need to able to take the financial risk of guaranteed physical delivery of DSR to different market actors – which could be a significant exposure (the aggregator being the contract counter-party with other market actors).

- **Nature of governance and licence arrangements** - needed to oversee technical and commercial aggregation activity – including possible ‘physical’ and ‘non-physical’ trading in different parts of the market.

- **Approaches to monitoring and verification of DSR delivery** - will need to be resolved.

- **Customer relationship –** nature of contract terms – including (1) customer non-delivery (i.e. non-performance, penalties etc) – and (2) transparency for customer as to how far any earnings from their DSR activity are being shared with them by the aggregator and / or optimised.

DSR price visibility and transparency

108. As of today, it is hard for a would-be DSR service provider – be this an individual customer or an aggregator - to make an informed judgement about what avoided-cost benefit / savings their prospective DSR actions or activity could offer to different market actors – including in different time-scales and at different locations.

109. Some price information is available in the market – certainly for Balancing Services – but as of today such price information is not necessarily readily accessed by all those who may have an eventual interest in providing DSR (e.g. customers ; suppliers ; aggregators ; local authorities; social landlords ; others).

110. This suggests a need for visibility and transparency of DSR price information to enable an element of DSR 'price discovery' for customers and others interested in providing demand-side services. This may be an initial but nonetheless helpful step to better understand what a hierarchy of demand-side services might look like in time.

111. Our own efforts to understand where most potential avoided-cost value sits for customers in the market today suggest that this is currently not readily done (viz Strawman 2, Section II). There appears to be a role for electronic platforms and exchanges which could to start to provide more and wider DSR price information, in support of DSR market development[52].

112. Other issues relating to improving information and communication throughout the market were also raised : eg forums to improve mutual understanding between different market actors and customers.

[52] With minor exception, Power Exchanges today are currently focused on prices and trades in the wholesale electricity markets.

(2) Socialised charges, load profiles, half-hourly settlement, and cost-reflectivity

113. A recurring theme in discussion with both suppliers and DNOs was that for all but the largest half-hourly settled customers, very many underlying costs in the electricity market are recovered from customers via industry charges which are socialised across non half-hourly customer groups[53]. This is the case for many of the costs relating to production, networks and balancing. From a DSR perspective, this has the dual-effect of :

- Making it difficult for an individual market actor to realise the full potential avoided-cost value associated with specific demand-side investment, measures or actions.

- Dampening value available to share with an individual customer via DSR price incentives / tariffs - because any resulting savings in industry charges are currently shared across the customer base.

114. Socialising recovery of most customers' half-hourly costs in the market serves to smooth prices throughout the electricity market – and so reduce customer exposure to short-term price extremes. As electricity is produced exactly when needed and (currently) not readily stored, from a customer viewpoint this has merit.

115. **For the largest I&C electricity customers who are half-hourly settled**[54] - many of the charges associated with energy production and transport are already passed-through to them directly by their energy supplier on a half-hourly basis – and in a visible way. This is true for: I&C customers' energy charges (to some degree) ; avoided Transmission charges via TRIAD management ; via the seasonal TOU element in Distribution charges. From an I&C customer viewpoint, effectiveness of these price signals in encouraging DSR depends, inter al, on : their direct visibility as a 'pass-through' (which they mostly are) ; and, importantly, given the many direct demands of running their core business, on how these charges combine to impact as a disincentive to peak-related usage.

[53] This is a highly complex area, and we cannot do it justice here. We are likely to return to these issues in future papers.

[54] i.e. ~ 117,000 customers at 100kW plus whose annual consumption amounts to ~40-50% of total annual GB electricity consumption.

116. **For the 29 million Load Profile 1-8 customers who are not half-hourly metered and settled** – the ability to reflect to an individual customer the half-hourly costs associated with their consumption *as it varies through the course of a day* - does not exist in today's GB electricity market arrangements[55].

117. In theory at least, greater cost-reflectivity at every level in the market might help to allocate costs more directly to where they are created / arise – and so pin-point where most avoided-cost value from DSR might exist.

118. However, even if greater cost-reflectivity could in theory help to crystallise where most available DSR value sits in the electricity system – it may also prove very controversial from a customer and consumer perspective. Any attempt to unwind the current socialised basis for charges – and to reflect this through into retail tariffs - would create winners and losers.

119. Examples of how cross-industry half-hourly charges are currently socialised with respect to non-half hourly customers[56] are described in more detail in Annex 6. These include :

- Wholesale costs
- Balancing costs
- Networks – TNUOS (Transmission Network Use of System Charges).
- Networks – DUOS (Distribution Use of System Charges) [57].

55 Current non half-hourly metering does not offer a facility to record *actual* consumption in any particular half-hour for an individual customer in Load Profiles 1-8. In practice, the industry's costs of production, balancing and transport are settled on the basis of eight *standardised* half-hourly Load Profiles 1-8. Without half-hourly metering, the *actual half-hourly* consumption of any one individual customer cannot be directly matched to the half-hourly cross-industry charges payable by market actors via the settlement system.

56 For each Load Profile 1-8

57 Charges for ***connection*** to the transmission and distribution networks are socialised only to the extent that connection charges are 'deep' or 'shallow' – ie how far the 'knock-on' costs of network re-inforcement are charged directly to the customer who is connecting (or upgrading) generation or demand – or – charged across all customers. See para 39 on DNO Trials of Non-Firm Connection Agreements for new load.

Development of Better Load Profiles and Eventual Half Hourly Settlement

120. With many industry costs being recovered from non-half hourly customers on a socialised basis[58], from a supplier perspective this means that :

- **Commercial incentives on suppliers are weak in terms of encouraging their non-half hourly customers to shift load or to avoid use at peak / high cost times of day.** Even where in principle, suppliers can see ways to realise cost-savings by encouraging their customers to shift their load via ToU retail tariffs, suppliers currently have little direct financial incentive in the market to develop time-varying retail tariffs at scale (static ToU, dynamic etc) because :
  - Any specific benefit created by an individual supplier is shared equally among all suppliers. Cross-industry charges would become *universally* lower and any benefit created in effect shared with their competitors.
  - New financial risks could arise for a supplier if their customers' consumption patterns start to deviate significantly from the standardised Load Profiles - against which industry cost-recovery takes place[59].

- **Poor supplier cost-alignment looks set to increase going forward** - with customers adopting new low carbon technologies such as micro-gen, PV and / or new electrical loads, such as EVs and HPs, which are creating new costs in, for example, the distribution networks.

121. In discussion, two key ways were raised to resolve current poor alignment of commercial incentives for DSR for suppliers with those of other market actors.

Development of More and Better Load Profiles

122. **Development of more and better load profiles** - against which suppliers could increasingly recover costs on a basis which provides a more accurate reflection of the daily usage patterns of particular customer groups. This was seen as a useful first step by some suppliers in starting to help individual suppliers begin to realise the benefit of demand-response or demand-side investment they might make. For customers, new load-profiles may or may not offer savings. That would depend on the retail tariff offered.

58 In effect, ~50% of annual electricity consumption – ie consumption by Load Profiles 1-8

59 For their non half-hourly customers, *in any given half-hour*, suppliers settle their total metered off-take against the standard industry half-hourly Load Profiles 1-8.

Example – a load profile which might incentivise a supplier to offer DSR tariffs (ToU or automated) to customers to self-balance their micro-gen with some form of thermal storage (e.g. heat). Without a load profile for that kind of usage pattern however, suppliers would continue to be settled on energy contracted according to standard household Load-Profile 1 – and so a supplier would not stand to benefit from any self-balancing action they may encourage their customer to take.

123. However, a move to developing more load-profiles in the relatively near-term in itself raises a number of questions, including :

- Which new profiles to select for early development – and criteria for their selection (Three-rate static Time of Use ? Large user ? Small User ? PV ? All-Electric Heat ? On-Peak Electric Heat ? Off-Peak Electric Heat ? Electric Vehicle ? etc).
- Likely time-scales involved in development of adequate new Load Profiles.
- Whether and how fast suppliers may reflect any such new profiles into retail tariffs (on the assumption that customers would be free to 'opt-in').
- Implications for 'winners' and 'losers' in any new approaches to cost-allocation: for example, among existing LP1 customers, PV FIT customers etc.

Half-Hourly Settlement

124. **Half-Hourly Settlement** - longer-term, and once smart meters are rolled out - and there is a fully functioning DCC (Data Communications Company) – to consider how best to look towards eventual full half-hourly settlement for all customers, including households. At that point, suppliers would be able to realise the full avoided-cost benefit to themselves of load-shifting measures taken by their customers – and so potentially align their own half-hourly costs (energy, imbalance, network) more accurately with the half-hourly usage of their individual customers.

Possible Example
Wind may support an integrated business in creating storage options. However, unless there is half-hourly settlement relating to when the stored electricity is later used by customers, the generation revenues for that company might reduce. Also, the storage might serve to reduce the peak-related costs of competitors.

125. In discussion a number of suppliers voiced concern that without adequate prior information and / or half-hourly settlement, new and unacceptable financial risks and exposures may arise for suppliers in the longer term (and which may ultimately lead suppliers to seek an additional 'risk premium' from customers in retail prices).

126. For example if suppliers' non-half hourly customer load was switched-around in the networks ***at scale*** by a third party (e.g. a DNO) in an 'unpredictable' way – i.e. without suppliers' prior knowledge and / or involvement. Suppliers need to be able to adjust / match both their wholesale contractual and their imbalance positions. For much of their power, they contract many months ahead in the wholesale markets – especially for household customers[60]. In effect, actions at scale by DNOs for low-voltage peak-avoidance (i.e. automated DSR involving EVs or HPs) – of which suppliers were not pre-notified - could leave suppliers with large unremunerated costs in both the wholesale and balancing markets. Some DNOs judged these risks as remote, on the grounds that suppliers would almost certainly be pre-notified of large-scale DSR actions by a network, and so would adjust their contractual position.

Possible Example :
If a DNO introduces measures *at scale* designed to avoid costs of network reinforcement – e.g. storage ; non-firm connection agreements – or other DSR ; – then without full half-hourly settlement the (most likely modest) avoided-cost benefits to the network are (ultimately) shared equally across each supplier on that network, via standardised DUOS charges. At the same time, individual suppliers may find the DNO peak-avoidance measures detract from value of their specific investments – e.g. exports from DG, PV, or, a supplier selling fewer units of electricity – although they will have taken a wholesale position perhaps months ahead - and also a balancing position one-hour ahead.

[60] but trade short term / hedge to adjust exposure

127. Potential risks to suppliers for the future were also discussed with respect to DSR contracted by aggregators in STOR, but generally, Balancing arrangements were seen as potentially less problematic[61].

Greater Cost Reflectivity – How Far, How Fast?

128. If in time, there is full half-hourly settlement for all electricity customers – large and small – the door opens on a move away from the current basis for socialising cross-industry charges for non-half hourly customers[62]. Many questions of principle would arise as to how fast and how far cost-reflectivity in end-customer retail tariffs might sensibly develop. Many questions of fairness and equity would arise.

129. We will return to these questions in later papers.

130. However, some examples – which we do not necessarily advocate - but which arose consistently in discussion - of how greater cost-reflectivity could potentially send a stronger and more direct price signal to customers - and which might therefore act as a sharper economic incentive to encourage DSR activity on an avoided investment cost basis, might be :

- **More locational approaches to charges –** In considering the eventual role of greater cost-reflectivity, the value of avoided-costs from DSR ***at specific locations*** will become increasingly important. This will be true for DSR in Balancing, in wholesale energy, for managing transmission constraints, and in the distribution networks.

[61] This was apparently because :
- Most STOR DSR contracts are currently with half-hourly I&C customers – and I&C supply contracts are likely to require I&C customers to advise their supplier of material change in their load.
- In STOR, any DSR feeds into imbalance price calculation – and is therefore, so far as possible, factored into a supplier's FPN contractual position ahead of gate closure (supplier Final Physical Notification at one-hour gate closure).
  In STOR, potential socialised generator or supplier losses associated with DSR of non-half-hourly customers may be relatively modest.

[62] i.e. presently based on an individual customer's kWh consumption – apportioned over the half-hourly periods in each of the standard customer Load Profiles 1-8.

- **On Low Voltage Distribution Networks -**

    - **DUOS** – to reflect possible peak-load (p/kW) and / or time-of-day elements ?
    - **Connection** – e.g possible load-related charges for connecting new load such as EV, HP ? Possible non-firm connection agreements ?
    - **Location-related charges** – specific ways to reflect locational benefits of DSR outside present universal p/kWh approach to LV distribution charges ?

- **Wholesale Costs** – time-varying energy costs via retail tariffs. (Static ToU, Dynamic)?

(3) Industry interactions and drivers for DSR

131. A recurring topic in discussion was how far present industry drivers and relations between market actors may serve to facilitate and / or impede DSR. As noted above, this relates partly to the socialised nature of many of the industry's charges, and the poor incentives which then arise – but not just. There is also a mis-match between some basic industry business drivers and future DSR development.

132. On the one hand, for example, suppliers have a lead-role with customers, some potential for avoided-cost value from DSR, but few commercial drivers / incentives to promote DSR among their customers (other perhaps than as an 'energy services' offer). On the other hand, DNOs, who lack a clear or direct interface with most customers, may in the foreseeable future have reasons to promote DSR from an avoided investment perspective, while having relatively little avoided-cost value to share at the individual customer level (unless location specific).

133. The paragraphs below consider some of the issues raised in discussion about this apparent mis-match in drivers for DSR for suppliers and the distribution networks.

134.

Suppliers

135. Some suppliers are currently exploring commercial approaches to better alignment of ToU incentives, with distribution networks, via LCNF trials. However, in general, suppliers can see limited avoided-cost value from DSR today due to :

- Weak incentives due to socialised industry charges.
- Both wholesale and balancing costs needing to be considerably higher than today[63].
- More substantial shiftable load would be needed than available today (eg heat or EVs at 2-3 kW constant) for avoided-cost potential for suppliers to become more material.

136. Supplier incentives for DSR are therefore currently weak, even though customer relationships are supplier-led. However, with smart meters and eventual half-hourly

[63] Domestic and SME tariff development for the Customer-Led Network Revolution. A Report prepared for Northern Powergrid. Frontier Economics. May 2012. For example, see Table on p.82.

settlement potentially enabling greater cost-reflectivity in charges – suppliers may become better incentivised to take an active lead with their customers on DSR.

137. In the interim, integrated suppliers are trying to better understand potential 'holistic' value across their businesses of better management of wholesale price risk / peak management. Some obstacles discussed which stood in the way of suppliers realising DSR value which may otherwise be available to them were :

- **Imbalance pricing calculation** - driving over-contracting for generation / risk-averse positioning in the wholesale market (an asymmetric incentive).

- **Upstream / downstream commercial drivers and incentives may not necessarily align across an integrated business**. For an integrated supplier, DSR could arguably potentially destroy value – eg lower sales ; expose to higher levels of imbalance risk if not well-coordinated ; could impact on economics of peaking plant (where fixed costs recovered via high prices – eg OCGT maintenance, connection costs).

- **Arms-length relations encouraged across integrated businesses from a regulatory perspective** – which may serve to inhibit value capture.

- **For most customers, few accessible single large -point loads readily available today to switch in bulk at peak** (eg Economy 7 storage heater type-loads) – but which may change with EVs / Heat.

138. Suppliers see growing scope to explore value by developing new customer 'offers' which combine DSR with energy services and low-carbon technologies. Some suitable new load-profiles would be needed.

Distribution Networks

139. **I&C Customers -** DNOs have a direct relationship with their largest customers, connected to EHV and HV networks, via existing (or new) connection agreements. Also, for half-hourly I&C customers, ToU DUOS charges are directly visible to these customers, albeit via the agreement with their supplier. As noted in Section I, both of these DNO inter-faces with larger customers do in fact already offer DNOs some opportunity to explore the potential for avoided-cost in the networks via I&C customer DSR.

140. **Households and smaller enterprises -** However, for most of the 29 million customers connected at lower voltage to distribution networks, DNOs currently have no active or visible customer relationship. DUOS charges are payable by the supplier - not the customer. DUOS charges are therefore currently a non-existent or at best a weak signal

to most customers ; amount to less than one-fifth of the final electricity end-price ; are levied at one remove from the customer ; and are not separately itemised, nor indeed visible, in most customers' electricity bills.

141. In discussion, issues which may start to increase DNO visibility (or role) in terms of developing and / or having a direct customer relationship to seek to actively promote avoided network investment costs - and so potentially promote DSR - were :

- **Splitting out Distribution charges in customers' bills.** This is already done for I&C customers, but may be relevant for other customers too if at some point ToU and / or location-specific price incentives were to be incorporated into distribution charges. In principle, this could be for network connection, network usage, or both.

- **Information on new load connecting to distribution networks** – from the point of view of network planning for investment to meet required security standards, there is currently great uncertainty as to where on the low voltage network new load may connect in the future. This is a particular concern to networks with respect to additional single large loads such as EVs and Heat Pumps, which may affect network resilience and so require capital spend on reinforcement – especially where these loads 'cluster'. PV installers are required to notify a DNO post-installation (which they do). In principle, the Distribution Network Code requires customers to inform DNOs of a material change in load – but this is currently neither widely known nor adhered to[64]. 'Requiring' low voltage customers (mostly households) to inform DNOs of material new load, raises questions of principle about status quo, equity etc - and from a customer viewpoint could perhaps be contentious. However, one possibility proposed by the ENA, is to link registration for RHI funding for a heat-pump to notification of installation of that heat pump to the DNO. This seems a potentially helpful step.

[64] PV Export – Post-installation, there is a requirement to notify the DNO of micro-generation up to 3.68kW (output of say ~3,000kWh pa) – and installers mostly do so. Above this threshold, the customer must seek prior permission.

Notification requirements in respect of new load are less clear - but an existing customer is already required (in principle) to report if there is a 'material' increase in their connected load. Example loads : EV – 6-7kW (if fast charge). Otherwise ~3kW connected ; Heat Pump – 2-3kW constant.

In practice, DNO assumes 1-2kW maximum load at low voltage per customer 'after diversity'.

- **Household smart meters** – from a distribution network perspective, a smart meter capability to remotely switch household load at scale - eg for heat, thermal storage and EVs – in order, potentially, to avoid investment in the low voltage networks. Switching load at scale requires staggered switching and technical co-ordination for system stability reasons (as with the existing Economy 7 Teleswitch facility. Again, this also potentially suggests scope for DNOs to have a more direct role with customers – for example via load management tariffs. For maximum effect, any such tariffs (ToU, automated load management) might potentially best align with supplier energy-related ToU tariffs.

- **Customer-facing skills** – unlike suppliers, currently not a core skill within Distribution businesses.

- **Distribution System Operator role** – potentially a longer-term development for managing and optimising active load on the distribution networks – be it distributed generation and / or demand. Changes introduced in DPCR 5 mean that DNOs are incentivised for total expenditure rather than capital expenditure alone. However, in the long-term, new forms of incentive designed to ensure efficient system balancing at distribution levels may also be needed.

- **Bringing distribution and supply activities more closely together at a local level to better integrate the supply and demand-sides** – for example, exploring ways to develop more integrated relations between networks, communities, local authorities and suppliers.

(4) Pre-disposition to generation solutions

142. Understandably, for historic reasons, there is a market-wide pre-disposition to generation solutions, rather than DSR. These include the following.

143. **Industry Rules** - a number of examples of how industry rules tend, somewhat inevitably, towards generation. For example :

Example 1 - ENA Engineering Recommendation P2/6 on security of supply in Distribution Network. Allows distributed generation to be taken into account in calculating compliance with security standards at HV – but not DSR to the same extent[65]. In this regard, industry rules may need review in due course – subject to establishing DSR ability to deliver (see below).

Example 2 : Imbalance Mechanism – Both integrated and independent suppliers commented on a bias inherent in the Balancing Mechanism price calculation towards over-contracting for generation (ie a bias to contract long on 'system sell' price to avoid the financial risk of being under-contracted for generation). Being under-contracted for generation led to a disproportionate (asymmetrical) financial risk – which in turn acted as a deterrent to developing demand-side initiatives[66].

144. **Commercial Drivers** **-** a range of commercial drivers tend towards generation solutions.

- **Customers –** I&C customers are inevitably pre-occupied with delivering their main business – rather than energy management. I&C customers may therefore not deliver 'declared' DSR on the day; may move their operations, or close a business unit capable of providing DSR. Uncertainty around customer-delivery will inevitably drive market actors to look more towards generators – for whom delivery is their main business – or to equipment oriented solutions – than perhaps to I&C customers. These

[65] Footnote 36 above

[66] System Buy price (i.e. the price at which market actors can offer to buy-back units of output from the SO if demand is lower than contracted) is inconsistent. For the same half-hour, a supplier can regularly be faced with a System Buy price differential of ~£10 / MWh e.g. can range between £40-50 / MWh – so very difficult to manage if *under-contracted* on generation. This apparently stems from previous changes to rules for imbalance pricing designed to address certain wind-related issues.

points are also likely to be true for households and smaller customers (unless automation).

- **Networks** – transmission and distribution networks are asset-based businesses. Even though there are many regulatory measures and incentives designed to counter-act network bias towards asset-based solutions, (viz RIIO), networks are nonetheless largely asset-focused. Network returns partly relate to the size of both their regulated and non-regulated assets - driven by generation connections – over which networks have no control.

- **Integrated supplier -** For an integrated company, 'pure' DSR is not a product which is directly equivalent to generation: reliability not as great (ie generation more 'guaranteed'); potentially undermines economics of existing flexible / peaking plant by suppressing prices. DSR, including upfront investment, would need to offer unequivocally higher returns to the business as a whole.

  Example :
  DSR vs peaking generation is an asymmetric risk for integrated companies. - DSR could in theory save peak plant operation – but, at scale, peak-saving from DSR may potentially (1) depress the wholesale price and (2) might thereby improve the revenue position of competitor generators both in the wholesale and balancing markets (unless full half-hourly settlement). In contrast, running a peaking or flexible plant earns a return on existing assets for the generator concerned ; does not benefit competitor generators by depressing the wholesale price ; and ensures a reliable supply, in a way which DSR may not.

145. **Reputational Drivers –** a strong market actor perception that risk of non-delivery is not symmetrical - eg failing to deliver promised DSR for Balancing or other purposes (e.g. in networks, for capacity) – and failing to deliver a secure supply. Not only would failed DSR delivery risk a financial penalty – but also, importantly, could well damage company reputation in risking supply-security. Market actors have understandable concerns at shifting well-understood and known engineering risks into possible commercial and reputational risk.

146. **Engineering mind-set** – unsurprisingly, the electricity industry has tended historically towards supply-side solutions, but this seems to be changing.

147. **Distributed and Back-up Generation versus DSR –** potentially raises some important questions[67].

- Distributed and back-up generation provides the lion's share of today's DSR – and involves a mix of modern distributed gas-fired CHP plant – as well as smaller back-up diesel plant (split not known).
- NG estimate that currently, over three-quarters of non-BMU STOR by contracted volume is provided by such plant.
- Network DSR - TRIAD management and DNO fault 'insurance' also entail back-up generation.
- Back-up generation has some CO2 associated with it – whereas 'true' DSR may reduce OCGT / CCGT output (and so offer a potential CO2 benefit).
- Some aggregation activity seems to be focused on contracting for back-up Diesel. For a large I&C customer this is a sunk asset – which may sit idle for much of the time – with an annual maintenance spend (eg ~£10k pa). Contracting in STOR entails relatively little risk – either for customer or aggregator. Allows customer to keep asset going : without liabilities or upfront capital expenditure.
- A recent LSE paper noted an EA Technology estimate of 20 GW of installed back-up plant in the UK – albeit not known how much of this suited to demand-side participation. In the same report, Npower estimate ~3 GW back-up today with an estimate for 2020 of 5 GW[68].

[67] Some of these questions will be considered in Paper 6 on Distributed Generation.

[68] 'Demanding Times for Energy in the UK'. London School of Economics. Grantham Research Institute. A report commissioned by RWE-Npower. November 201. P.24.
The paper notes that stand-by generation 'has until now, been used almost exclusively as protection against unplanned interruption, particularly from faults in the local distribution grid'. Examples the paper gives of organisations likely to have stand-by generation include : data warehouses ; water and sewerage pumping stations and treatment works ; telephone infrastructure ; large offices ; hospitals ; research laboratories ; factories ; manufacturing facilities and the military. They give the example of Wessex Water – as having 550 generators totalling 100 MW. Of these, 18MW across 18 units are linked to a control system for automatic operation at times of high electricity prices. The paper also notes that there is no official data on the amount of back-up capacity but that 'EA Technology has estimated that total UK capacity of emergency diesel generation at 20 GW'.

148. **A need to first establish that DSR / innovative solutions *can* deliver** - before turning away from supply-side solutions. Lessons from LCNF, other trials, practical examples – (both helpful and unhelpful) - will therefore be very important.

149. **A changed mindset towards DSR** - industry-wide acceptance and confidence in DSR solutions for GB is more likely to follow, once DSR potential is better understood and a clear role established.

(5) Customer Loads & Market Actor Needs – How Do They Fit Together ?

150. Many customer and consumer issues need to be better understood before large-scale customer interest in DSR is likely to be unlocked. We will return to these issues in Paper 8.

I&C Customers

151. Section II showed how, as of today, half-hourly I&C customers are the ones most likely to access a revenue stream from the avoided-cost potential which DSR may offer – most likely from providing Balancing services (and also by avoided transmission charges from TRIAD management). In the next few years, DNOs are also looking to I&C customers to provide DSR as additional pre- and post-fault 'insurance' at EHV and HV to defer or avoid network reinforcement.

Household Customers

152. Today, other than Economy 7 and LCNF trials, there is limited interest from market actors in household DSR, for reasons identified in this paper.

153. However, for the long-term, household load could in theory play a valuable role in GB DSR development because :

- Household consumption is one-third of all annual demand today.
- Household load contributes to year-round morning and evening peaks (in particular) – which are costly to meet - especially in winter.
- Household load connects in the distribution networks at Low Voltage.

154. Unlike in countries with extensive household air-conditioning or electric heat, GB households today offer relatively few large single switchable loads – except possibly on-peak electric heat[69] . Also, estimated cost-savings for market actors to share with households for their DSR potential pre-2020 is modest on a per customer basis (eg ~£2-

[69] 14% of all electricity used by households today is for space-heating – both peak and off-peak(~16TWh pa). This splits fairly evenly at ~8TWh pa each between on-peak electric heat and Economy 7. On-peak heat as a main heating source is growing as a proportion of electric heat, and estimated to involve 2-3% of GB households. See Sustainability First GB Electricity Demand Project - Paper 3 on Household Demand.

£4/customer/pa for direct control of wet appliance load at evening peak)[70]. Taken together, these two factors make near-term DSR contribution from households likely to be modest, and with high transaction costs – leaves open the question as to how worthwhile household DSR may be in the relatively near term – either to market actors and / or to consumers.

Household Load and LV Distribution Networks

155. As noted, DNOs are already exploring I&C DSR at higher voltages, mainly for pre- and post-fault 'insurance' value. A number of DNOs described their view of becoming smarter at EHV and HV – where this is currently a more practical prospect – but inclining towards network reinforcement and investment at LV - in order to maintain a network which remains compliant with security standards as new loads connect.

156. Nevertheless, looking ahead long-term, and as indicated in Section I, much of the potential value of avoided investment for the distribution networks sits at low voltage. This would seem increasingly so, with uptake of new EV and HP load. The potential to avoid distribution network reinforcement at lower voltage could therefore come from :

- Electricity demand reduction of general household load.
- Load shifting EVs/HPs at specific locations – probably automatically. EVs are more likely to be readily shiftable at evening peak than electric heat.

157. Also, as noted, avoided-costs at low voltage from demand-side measures would also 'trickle-up' as an avoided cost-benefit, by creating new headroom on the higher voltage distribution networks too.

158. Possible tools available to DNOs for managing new loads at low voltage could include :

- Notification of (continuous) new household loads >2kW (perhaps, as noted, linked to customer registration for any related incentive scheme (RHI, EV)).
- Non-firm connection agreements for specific types of new load.
- Automated, direct control of shiftable loads (EVs, heat).

[70] Domestic and SME tariff development for the Customer-Led Network Revolution. A Report prepared for Northern Powergrid. Frontier Economics. May 2012. For example, see Table on p.82.

- Circuit-breakers or 'load-limiters' - linked to load-management tariffs (common in France and Italy) – but possibly somewhat controversial for GB. (LCNF trials will shed light on customer open-ness to such approaches).

159. In the near term, a number of factors stand in the way of DNOs introducing these kinds of direct customer DSR incentive :

- DNOs presently do not have a direct profile or interface with their household customers whereby load management options can be readily promoted or implemented via DNO charges.

- Unless and until there are new load-profiles and / or half-hourly settlement, the distribution-related savings available to share among customers will be small individual sums (because network costs are averaged across all customers) – and even smaller as a proportion of the end-bill.

160. Some interim approaches for DNOs to incentivise local customer DSR response might therefore include :

- **Joint action with a supplier**. For example, creating combined incentives in a static ToU retail tariff. The distribution part of the incentive may - or may not - be directly visible to a customer. Joint incentives of this kind are likely to have a greater impact because they will be more material in the end-bill (as per CLNR LCNF trials).

- **Separate 'side-arrangements'** - able to reflect location-specific cost-savings of DSR at a particular point on the network. Agreement may be needed on what basis such non-socialised incentive payments could be developed for households and smaller customers (presumably based on some yardstick of LRIC at that location). Also, other than a static ToU tariff, questions will arise as to how such DSR 'side-arrangements' could be accurately base-lined and monitored without new load-profiles or half-hourly meters. This possibly suggests somewhat limited scope for low-voltage DSR 'side-arrangements' in the near-term.

161. Should insufficient value be available to share with customers, or should household and smaller customers in the end prove reluctant to avoid significant local increases in network loading during the evening peak, DNOs may eventually look towards some kind of direct financial contribution towards local network re-inforcement. For example, via :

- Some form of new household-load connection charge / payment.

- A localised DUOS charge

162. In the long-run, with possible new load-profiles or eventual half-hourly settlement, the option of greater cost-reflectivity becomes a reality. At that point, DNOs may be able to share more significant rebates / discounts with specific groups of households – or even individual householders – able to curtail or shift load at specific locations on the low voltage network on a firm basis - provided this enabled sufficient deferral / or avoided network reinforcement at that location. Such rebates on distribution charges may be incorporated into retail tariffs. Or, they might remain a separate 'reward' / incentive payment direct to the customer.

Households - Peak Shifting in the Longer Term

163. **Without significant uptake of EVs / electric heat / household-level thermal storage** – there could remain relatively modest 'realisable' GB household DSR at evening peak. However, in such a low take-up world, distribution networks may not face such strong pressures for new network re-inforcement / investment.

164. **Significant uptake of EVs and electric heat** - will in principle enable household load to be shifted at peak – and / or automated – and thereby could : facilitate avoided low-voltage network investment ; enable household self-balancing ; enable households to respond to high-priced periods in the electricity system from wind intermittency.

165. **With automated EV and heat-load at scale** – households could in principle provide DSR services to *all* market actors – not just DNOs - including potentially some balancing services (e.g. automated frequency and fast reserve) ; peak avoidance to the transmission and distribution networks (EVs especially). Automated household peak-avoidance of EVs and heat could therefore align well as a potentially valuable service throughout all parts of the market – wholesale, balancing, networks - possibly even the capacity market.

Household Electricity Demand Reduction on the LV Networks

166. More generally, household electricity demand reduction could also be an effective measure to help avoid network investment at low voltage – including today (ie assuming a possible range today of ~£40-60/kW/pa of avoided investment). However, given DNO lack of direct customer interface, it is not altogether clear on what basis DNOs would or could take direct steps to incentivise groups of households – or individual households - to reduce their *overall* electricity demand.

167. Two points follow :

- It remains important for others - government, Ofgem - to continue to prioritise policies for electricity demand reduction – because in addition to a carbon benefit and lower customer bills - electricity demand reduction may well also offer the added benefit of avoided low voltage network investment.

- In considering incentive arrangements for DSR in ED1, Ofgem may wish to explore how far DNOs are currently incentivised for electricity demand reduction, if at all. And, if not, whether such an incentive might sensibly be worth exploring as a potential means to achieve avoided network investment at low voltage. Many issues, including how to base-line measurement, would need resolving.

168. **Local authorities, communities and social landlords** may also have a role to play in taking on an aggregation role to deliver avoided network re-inforcement at particular locations (non-firm connection agreements ; security achieved through curtailing community-level load (rather than security via assumed individual household load diversity); micro-gen / heat integration via automated remote control. In theory, aggregation of many different / diverse loads – I&C and household - can deliver the 'right mix' of required DSR response-time, load-shape and volume. Importantly, such community responses may only be required at certain times of the year, and/or certain times of day, depending on the nature of the new load at that locality (eg heat, EVs).

169. Distribution networks may be able to develop closer relations with local authorities, communities and / or social landlords somewhat more readily than with individual customers – and more readily share at community level one combined (larger) value from avoided network investment. They in turn may be well-placed to realise local schemes which can address location specific problems. Local authorities may in time need to become licensed suppliers – or at least work closely with a licensed supplier.

Example 1
Ashton Hayes Village, Chesshire - DNO gaining insight into community level end-use and local transformer and substation loadings [71].

Example 2
Social landlord CESP scheme[72] where Economy 7 off-peak heat replaced by Air Source Heat Pumps in ~200 homes. Maximum customer load has shifted from 6kW

[71] See Ashton Hayes website for monthly load-profile

overnight to 1.5kW day-in-day out. As a result the 'collective' load profile of that housing development is now one-quarter of what it was – but constant over 24-hours - rather than at 100% of load over seven hours at night. This in turn means that the local distribution network can possibly meet required security standards, without re-inforcement.

170. Eventually, new sources of DSR from customers – automated, aggregated, aggregated at community level - may include :

- **Lowering voltage** – a 2% voltage reduction, potentially reduces power requirement by 1% (may suit winter anti-cyclones).
- **Commercial sector** – heating, ventilation, cooling, lighting[73].
- **Household peak-avoidance** – most value likely to be obtained at specific network locations to shift EVs & / or HP load on an automated basis.
- **Household self-balancing of PV** – with storage to enable reduced usage at peak-times (possibly heat storage) – equates to 'back-up' generation at a household level.

[72] Toryglen, Glasgow.

[73] Demand side response in the non-domestic sector. Final report for Ofgem. Element Energy & De Montfort University. May 2012.

IV Initial Conclusions

171. This paper has attempted to reflect discussion with thirteen market actors about which demand-side services can provide value to the electricity sector. The paper covers a great deal of ground. It is in no sense definitive and raises many questions. We will return to a number of these issues in our later papers. Initial conclusions are as follows.

172. There is a need to develop a better understanding of where cost-savings and value may sit within the electricity system from avoided-costs which may result from Demand-Side Response (DSR). LCNF trials will certainly help – but represents only one part of a bigger picture.

173. Today, I&C customers (half-hourly) are providing some DSR to some market actors. They may be able provide more - if sufficient cost savings are there.

174. The issues and barriers outlined in Section III also need to be addressed if market actors are to realise more avoided-cost potential from DSR – and to enable market actors to pass any savings to their customers.

175. Until there are more load-profiles and / or full half-hourly settlement, market actors may struggle to realise much DSR value from the vast majority of smaller / individual customers (unless, possibly, at community level). Also, more 'shiftable' load would be needed than customers have today – plus - load which lends itself to automation (electric vehicles, heat, thermal storage).

176. In the near-term, electricity demand reduction may offer some avoided-investment potential for Distribution networks at low voltage – and also cost-savings for smaller customers / households. In considering new incentive arrangements for DSR in ED1, Ofgem may wish to explore how far DNOs are currently incentivised for electricity demand reduction, if at all. And, if not, whether such an incentive might sensibly be worth exploring as a potential means to achieve avoided network investment at low voltage.

Annex 1

Examples of Demand Side Response procured by Market Actors

Distribution Network Examples

DNO Example 1

Non-Firm Connection Agreements

Aim - For both DNO and customer, the benefit of a non-firm connection agreement at a particular point on the network, is the **avoided-cost of additional / 'deep' network re-inforcement** which may result from the connection of that particular customer (or group of customers) - the cost of which would otherwise be apportioned between:

- An up-front charge to the connecting customer; and
- Socialised and recovered from all network users via DNUOS.

Connection Agreements / Assets & Charges - Generators and large customers have agreements which specify the technical characteristics of their local electrical connection with the DNO. A connection agreement relates to providing the physical assets (e.g. local transformer, cable etc.) needed for a safe and secure connection for the 'required capacity' requested by that customer at that point on the network. Annual use of system charges are calculated on the incremental costs of providing capacity. Connection agreements can be either 'firm' or 'non-firm'-only firm capacity is liable for use of system charges.

Firm customers – both shallow sole-use connection assets and deep shared assets are designed, built, operated to the customer's requested 'required' capacity' – and charged accordingly. On average, a 'firm' customer can expect to lose supply once per year. A 'firm' large industrial customer once every 2-3 years. There is significant variation, depending where on a network a customer is located. In a town, firm customers may never lose supply – rising to 6-10 times per annum in remote rural locations.

A non-firm customer - opts for a lower up-front connection charge and lower ongoing use of system charges. In return, their connection assets are designed, built and operated to a level which does not guarantee output / load at their requested 'required capacity' at all times. For example, if thermal limits are approached at that network location, then the non-firm customer's load (or generation) can be curtailed.

- DNO has some generation, wind & industrial CHP customers – on non-firm basis

DNO Example 2

I&C DSR Trial

Contracts for Avoided Network Reinforcement – aggregation of I&C Load

Aim – to manage load-reduction at transformer in event of network fault.

I&C Trial – mid-Jan 2012 to end Feb 2012.

Three large I&C customers, recently struck contracts with two different aggregators for ~3.5 MW of DSR.

Experimental – aimed for aggregator-managed contracts capable of operating within existing DSR framework.

Approached customers already contracted via aggregator for STOR and TRIAD. TRIAD and distribution demand-side response (DSR) requirements can coincide. If DNO calls DSR, then that customer's demand has already reduced if there is also a TRIAD. If TRIAD called, then DNO also gets a reduced peak. STOR and distribution demand-side response requirements can also coincide in some scenarios. Some customers only participate in Window 1 of STOR leaving the site available for other DSR purchasers outside of that window.

Commercial : Contracted 3-7pm winter weekdays – November to February. Pricing structure developed on basis similar to STOR – ie a £/MWh availability payment and a higher £/MWh usage payment (currently, STOR £/MWh usage payment 20-30 times greater than STOR availability payment).

Technical : 3.5 MW signed. Each block desired to be >0.5 MW. Aiming for a load-shift of at least 10% (which, in theory, at today's demand levels could offer investment deferral of up to 20 years). Seeking Industry customer load-shape with good match to primary transformer load-shape at winter peak. Succeeded in finding good load-match for transformer and Industry-customer for winter peak – but not summer peak. Response times – akin to STOR requirements – i.e. 15-20 minutes notice and up to 3-4 hours duration.

DNO Example 3

- Engineering 'self-help' –encouraged by DNO to achieve avoided connection or reinforcement costs. For example, DNO has encouraged a couple of informal arrangements where network potentially overloaded / would need re-inforcing :

  (1) A large industrial customer was approached to move shift patterns by half-an-hour – successfully avoided need for network re-inforcement.

  (2) Two examples where created direct discussion between generator and large customer to reach a direct bi-lateral supply arrangement – resulted in avoided cost of connection (e.g. generator & large industrial customer ; a hospital).

- Potentially see a role for DNO in encouraging such engineering 'self-help' solutions – ahead of, for example, aggregation.

DNO Example 4

Economy 7

- DNO with large number of E7 customers for historic reasons. Several hundred MW of E7 Load mostly (but not all) managed via the Radio Teleswitch. [74]

- In one network location, DNO able to manage a thermal constraint by switching E7 customers – i.e. successful deferral of network re-inforcement.

[74] Likely that ~1 GW of UK household load is tele-switched (via the BBC Radio 4 signal) – roughly 2 million customers – (~6TWh p.a) - involving a load of ~6-9kW / household (average load around 5kW).

DNO Example 5

Switch from Economy 7 to Air Source Heat Pumps

> Social landlord CESP scheme[75] where Economy 7 off-peak heat replaced by Air Source Heat Pumps in ~200 homes. Maximum customer load has shifted from 6kW overnight to 1.5kW day-in-day out. As a result the 'collective' load profile of that housing development is now one-quarter of what it was – but constant over 24-hours - rather than at 100% of load over seven hours at night. This in turn means that the local distribution network can possibly meet required security standards, without re-inforcement.

- DNO Example 6
-
- Ashton Hayes Village, Cheshire
-
- DNO gaining insight into community level end-use and local transformer and substation loadings[76].

DNO Example 6

Industry DSR Trial

Contracted DSR from a single customer to ensure pre-fault compliance and so avoid transformer reinforcement.

Aim: In the event of a fault, to reduce peak demand to secure supply.

A large industry processing plant contracted to provide DSR at times of peak demand. This trial is ongoing and has been successful to date.

[75] Toryglen. Glasgow.

[76] See Ashton Hayes website for monthly load-profile

LCNF Examples

Customer-Led Network Revolution CLNR LCNF project - Northern Powergrid evaluating role of DSR in terms of scope for avoided capital investment - in the face of new connections of PV, Heat Pumps and Electric Vehicles at volume at Low Voltage. Outcomes expected 2014.

Low Carbon London 1– Wind Twinning trials[77]

Trial 'wind-twinning' electricity tariffs

Aim: investigate potential for domestic and SME customers to modify their electricity consumption time patterns, in response to renewable generation.

Trial offers day-ahead Time Of Use tariff which reflects generation – offering cheaper electricity prices at times of expected high wind/ high renewable generation.

Low Carbon London 2 – I&C Demand Side Response[78]

Aim: to learn about potential for peak-shaving through DSR.

Flexitricity, EnerNOC and EDF Energy are recruiting customers to join the trial.

[77] source http://www.flexitricity.com/file/LCL%20info%20pack%20short.pdf

[78] source http://lowcarbonlondon.ukpowernetworks.co.uk/join-our-trials/demand-response/

Annex 1 (continued)

Supplier DSR Examples

Supplier Example 1

- STOR - As an integrated company, generation arm provides :
    - Frequency Response
    - STOR – OCGT B-M Units
      Transmission Constraint Management – Non B-MU

- No STOR participation via load management / DSR, currently.

Supplier Example 2

- **TRIAD Management**

- Run distributed generation at a TRIAD period, to reduce TRIAD liability of the generator and associated client site (where applicable) e.g. CCGT associated to local distribution zone or CHP attached to industry.

- TRIAD warnings can occur up to 20 times per annum. In addition to National Grid, also use Trading Team to anticipate TRIAD warnings – and advise their customers as a 'service'.

Supplier Example 3

- **Transmission Network Constraint Management** –

- Supplier on occasion will support Transmission Constraint Management - by pulling back generation (i.e. negative demand) where their generating assets are within a Distribution zone, and sit behind a Transmission constraint. Revenue stream from constraint payments under BSUOS - to support system balancing.

Supplier Example 4

- **STOR -** one STOR contract. Mainly for learning, experience of tender process and aggregation. Using own-sites – and one customer / commercial site. Aggregating across three sites.

- Value currently limited. Associated upfront expenditure : installation of a Building Energy Management System (common in US) (if already an automated HVAC system, then expenditure less significant). Also, subject to email, phone call or signal from NG, will switch-on diesel generator. Main costs associated with managing multi-sites and sub-metering.

Supplier Example 5

- **Flexible Energy Management Contract**

- One example of innovative contracting by a supplier, is in offering a flexible product that allows the larger (30GWh+ per year) customers to buy energy in months, quarters or seasons, in and out of sequence. Customers have access to a dedicated product team as well as a trading desk for base-load and peak purchases. This gives added flexibility to the supplier – while also offering benefit to the largest customers, by providing more freedom, control and price transparency to that customer's energy purchasing.

Annex 2

National Grid – Description of Balancing Services

Frequency Response

National Grid procures frequency response services, to keep the electricity system frequency close to 50Hz on a second by second basis, by automatically altering the production or consumption of electricity in real time. A typical demand side provider of frequency response services would have electricity load that could be shed instantaneously and automatically in the event of a significant variation in system frequency. Trigger levels are set to statistically manage how many times per year this is likely to happen.

Fast Reserve

National Grid procures fast reserve to meet large, rapid rates of change of demand for which conventional power stations are too slow to respond. A typical demand side provider of fast reserve would be very large (e.g. tens of megawatts) and, upon receipt of an electronic instruction from National Grid, would be able to start backup generation and/or reduce demand very quickly (e.g. within a couple of minutes) and run for a short period.

Short Term Operating Reserve (STOR)

National Grid procures STOR during defined times of the day, in order to have reserves available to cater for general variations in demand and generation failures. A typical demand side provider of STOR would, upon receipt of an electronic instruction from National Grid, be able to start back up generation and/or reduce electricity demand within timescales of up to four hours, and be able to run for a couple of hours.

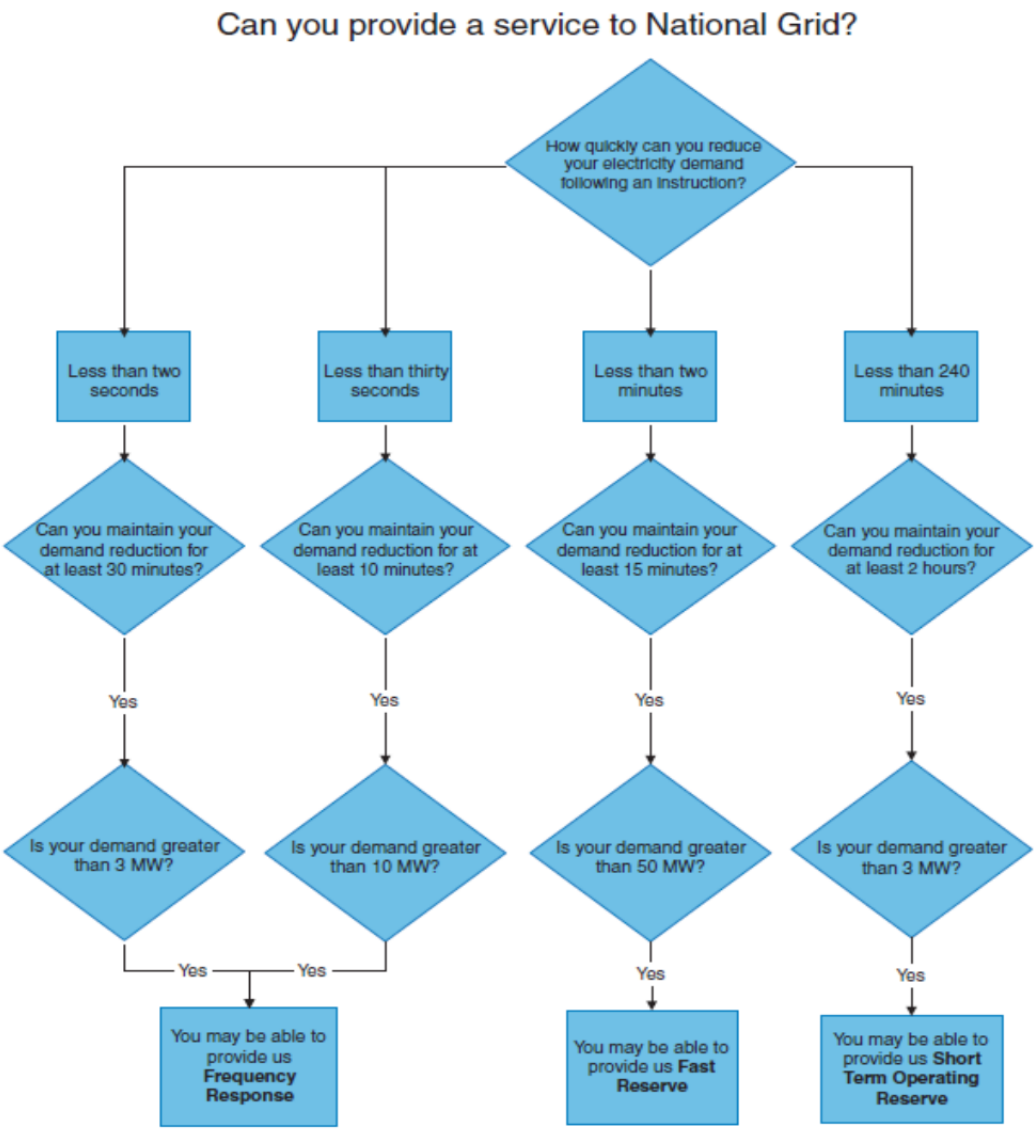
Constraint Management

National Grid procures Constraint Management Services to alleviate localised power flow constraints on the high voltage transmission network, for example during a planned network maintenance activity. A typical demand side provider would be able to, on a pre-planned basis, shutdown its demand or run backup generation continuously for a sustained period, e.g. a number of days. Occasionally the need for the service would only be for defined periods during the daytime.

Source – National Grid Website. Balancing Services. Demand Side. Service Descriptions.

Source – National Grid website.

Leaflet 2008 'Turn down your power, turn up your profit'.



If you have answered **Yes** to all questions than please contact using the details overleaf. Please note the faster you can respond to an instruction the greater the value to National Grid.

If you have answered **No** to any question then consider if you could achieve the requirements by aggregating loads together, this can be on a National scale. A number of companies also provide aggregation services, details of these can be found overleaf.

Annex 3

Transmission Network Use of System Charges
TRIADS and National Grid Demand Charges[79]

Almost three-quarters of transmission charges are levied from Demand – rather than from Generation (Generation : Demand split is 27:73 percent).

Demand charges are split into 14 geographic zones. In general, demand charges are lower in the north and higher in the south.

In each of the 14 zones, demand charges which are payable by a supplier are calculated on the following basis.

- **Demand Tariff for Half-Hourly Metered Customers** – applied to a demand-users average half-hourly metered demand over the three TRIAD periods. Demand Tariffs are a combination of :

- **Locational Charge** – which reflects the cost of providing incremental transmission network capacity to demand.
  Example : 2012-13 Charges
  - North Scotland zone - £10.74/kW
  - London zone – £31.17/kW

- **Non Locational 'residual' element -** £22.83/kW in 2012-13 (i.e. irrespective of zone).

- **Energy Consumption Tariff for Non-Half Hourly Metered Customers[80]** – is based on the annual energy consumption for each supplier in each zone (as per settlement) during the period 16.00h – 19.00h each day (settlement periods 33-38) over a (financial) year.
  Example : 2012-13 Charges
  - North Scotland Zone – 1.48p/kWh
  - Southern Zone – 4.34p/kWh

[79] Statement of the Use of System Charging Methodology. (April 2010). Chapter 4 on Demand Charges & Appendices TN-3 and TN-4. Statement of Use of System Charges. (from April 2012) pp16-19 on Demand Charges. National Grid website.

[80] ie Load Profile 1-8 customers responsible for ~half of all annual electricity consumption – ie 167 TWh of 322 TWh in 2011)

Annex 4

Charges for Distribution

The distribution networks recover allowed capital and operational expenditure for investing in and for operating the networks via DUOS charges (Distribution Use of System). Some of the costs associated with connection-related assets are recovered via Connection Charges.

Distribution Use of System Charges (DUOS)

The distribution networks recover allowed capital and operational expenditure via DUOS charges to meet the fixed and operating costs of investment, reinforcement, maintenance and repair of the network.

Suppliers generally pass-through DUOS charges to their half-hourly customers as a direct and separate charge (albeit perhaps not in every case).

For most of their non half-hourly customers, a supplier pays the network a per customer DUOS charge, which is not visible to the customer nor separated out in their end-bill. DUOS charges represent ~18% of an average household end-bill.

The Common Distribution Charging Methodology was adapted for the HV and LV networks in April 2010, and for EHV customers from April 2011.

Distribution charges payable by Half-Hourly settled customers connected at any network voltage (~117,000 customers) – incorporate a seasonal three-part time-of-day element (STOD), to provide an incentive for winter weekday evening peak-avoidance – which suppliers mostly pass-through directly. Red, Amber, Green periods.

All half-hourly I&C customers also have a separate capacity-related element in their DUOS charges.

For EHV directly-connected half-hourly customers - there is a high 'super-peak' charge at winter evening peak as a DSR incentive. Super-red time bands were introduced via the EHV Distribution Charging Methodology (EDCM) from April 2011 for EHV directly connected half-hourly settled customers. Super-red time bands are chargeable at winter weekday evening-peak across all DNO areas – except London where super-red time bands apply during both winter evening peak hours (16.00-19.00h Nov – Feb) – and summer months (11.00-14.00h June-August).

For larger Load Profile 5-8 customers (~166,000 customers) – some of whom who may be half-hourly metered but not half-hourly settled - there is a 2-part day-time and lower night-time p/kWh unit charge. There is also a fixed pence/day/ customer fixed charge to reflect fixed costs of supply – and a capacity-related element is factored into the calculation.

For the vast majority (29 million) LP 1-4 customers – connected at low voltage - there is a p/kWh unit charge (plus a night-rate for Economy 7 & off-peak customers). As for LP 5-8 customers, there is also a fixed pence/day/ customer fixed charge (in effect a standing charge) to reflect fixed costs of supply – and a capacity-related element is factored into the calculation.

Common Connection Charging Methodology

Non-Contestable Connection Charges - allows cost-recovery by DNO of necessary works / new capital assets to connect new generation and demand to its network to the requested 'required capacity' kVA.

Annex 5

Voltage Management

- **System wide** – National Grid currently manages voltage across the national GB electricity system via the Reactive Power market.

- **DNOs** - are required to maintain voltage within (statutory) tolerance of +10% / -6%[81]. At substations, visibility is needed - should volts drop.

- On the LV network, at substations below 33-11kV – there is currently very little control over voltage – and customers' voltage requirements are estimated. Voltage is set at the highest point at the substation – and thereafter voltage drops away with distance from the substation. There is presently no ready way of knowing where on the LV network voltage may need a boost. So, voltage is optimised / set high at substation level.

- Embedded PV on the LV networks increases voltage – and causes significant local voltage swings - so voltage management problems increase with more PV (and lack of visibility on this).

  Example 1 : Social landlord – PV. Voltage has increased.
  Example 2 : LCNF project (2011) Will look at the voltage dependency of load as one of the learning outcomes.

- Main DNO concern is to keep within statutory limits and to protect customers' resistive equipment from very low voltage – eg motors, TVs, bulbs, heat, kettles, A/C. Transformers (ie for non-resistive equipment) produce more current as volts drop – so, electronic equipment / induction motors are not vulnerable to poor performance from low volts in the same way. Inverters within PV installations may disconnect an array if voltage exceeds, say, 260 volts. This protects the network. Questions therefore arise as to how far a network must be re-inforced to meet maximum PV output.

- Reducing voltage can also be used as an emergency resilience tool. Reducing voltage causes load / demand to drop. In theory, if voltage drops 2%, then power off-take drops 1% - so this is potentially a relatively painless way to reduce demand. In

[81] If voltage too low, resistive equipment will simply not work (ie equipment not damaged as such) (NB-frequency excursions *can* damage equipment).

practice, the ratio for voltage reduction : power reduction is nearer 1:1. At distribution level, NG asks DNOs to reduce voltage / demand as a last-resort measure if there very are major system problems – but this is largely invisible and not factored into current commercial frameworks. Some initial DNO consideration on whether and how they can use voltage as a resilience tool.

- Voltage Optimisers – can reduce customer running costs by reducing input voltages from 240-245 volts down to around 230 volts. Reduces voltage by up to 16 Volts. Example : Tescos ; Downing Street. St Andrew's University – saved a few percent on their consumption. From a DNO point of view, voltage management may be less complex if managed *within* a customer property. Equipment payback periods may be an issue.

Annex 6

Socialisation of Industry Charges among non-half hourly customers - Overview

- **Wholesale costs** - suppliers contract with generators in the wholesale market (OTC, day-ahead, forward markets) for different time-periods – and settle half-hourly. Half-hourly prices do not reflect directly in retail-tariffs however. For most non-half hourly customers, retail tariffs are mostly averaged and flat, regardless of the time of day, time of year. Greater within-day price-variation in retail tariffs (eg ToU) could in principle allow suppliers to reflect wholesale energy costs more accurately to customers. However, this is unlikely without either more Load Profiles, or, full half-hourly settlement.

- **Balancing costs** – supplier imbalance charges are settled on a pence/kWh per-customer basis - based on the eight standard half-hourly customer Load Profiles – and do not reflect the actual half-hourly costs of imbalance at the level of an individual customer. For any given half-hour, supplier imbalance costs are socialised across all non half-hourly customers of the same load-profile.

- **Networks –**

  - **Transmission Charges[82] – Incentives for avoided investment - Peak Load management for non-half-hourly Load Profile 1-8 customers –** annual TNUOS charges payable by suppliers incorporate a pence/kWh charge (ie energy-related) which incorporates a peak-time element (16.00h – 19.00h all year). There is also a locational element. However, this currently does not create a direct incentive for suppliers to curtail peak-energy demand on the transmission network with respect to their 29 million non-half hourly settled customers. This is because of the socialised manner in which TNUOS charges are recovered by suppliers from their individual customers – whereby the benefit of any peak-avoidance action taken by one supplier at a particular Grid Supply Point is shared equally among every supplier at that GSP (on the basis of the eight customer Load Profiles). So, in terms of avoided transmission charges, a supplier is not incentivised to pass an avoided-cost message for

[82] See Annex 3 on Transmission Use of System Charges (TNUOS).

evening peak consumption between 16.00h to 19.00h to their individual customers[83].

- **Distribution Charges** – Suppliers pass-through DUOS charges direct to most of their I&C half-hourly settled customers connected at EHV, HV and LV, including the seasonal ToU element of the charge. For all other customers who are non-half hourly settled, Distribution charges are payable by suppliers as per the Common Distribution Charging Methodology[84]. Suppliers then recover these costs from customers on a standardised basis according to customer load profile. The recoverable costs are common to every supplier with customers on that distribution network - regardless of their customers' actual use at different times of day (ie morning, evening). This is so for all customers connected to the distribution network at low voltage, including all households. Thus the manner in which distribution charges are currently recoverable by suppliers from their customers, carries no incentive for suppliers to encourage individual customers to avoid evening peak consumption on the distribution networks (as any benefit an individual supplier may create is shared equally among all suppliers).

[83] Separately, TNUOS charges for non-half-hourly settled customers do in fact include a locational element in the suppliers' Demand charges (broadly, TNUOS Demand charges are twice as high in p/kWh in the south than in the north). See Annex 3 on TRIAD charges.

[84] See Annex 4

Annex 7

Questions Used to Structure Discussion with Market Actors

Paper 4 will be developed through a series of structured discussions with electricity market actors. The aim is to develop a better understanding of what demand-side services different market actors either need and / or would like to obtain from customers (I&C, household).

The main aim of the discussion is to explore current approaches to Demand Side Response (DSR) within your company.

It may be helpful to structure discussion under the following suggested question areas.

A. Current Approaches to DSR - for example :
Current role of DSR to your business ?
Nature of specific DSR 'products' or services sought – and why.
Nature of specific DSR 'products' and services presently obtained
How DSR is currently procured. Availability of DSR services and providers to your business. Who ? How easy to obtain ? Direct from customers ; via an aggregator ?
Key technical characteristics and services required by your business from DSR providers – eg prior notice, minimum MW, speed of response, potential for aggregation etc.
Present approaches to pricing / valuing DSR services by your business ?
The potential relative value to your business of different demand-side services which GB customers offer today.
Possible Technical Impediments to DSR ? How far do technical issues shape DSR procurement and development today ? Technical – equipment, metering, speed ; Monitoring and verification
Possible Commercial Impediments to DSR ?

How far do today's commercial arrangements support demand-side participation? Any notable gaps or shortcomings ? For example, information-sharing ? DNO charging arrangements ? Connection arrangements ?
Information - Scope to improve on information currently available to customers about demand-side participation : e.g. on 'core' technical requirements sought ; on potential value ; on price-information and price-visibility for demand-side services (including in different time-frames, different locations)
Communication - how market actors and customers might best communicate on such matters.
B **How market actor requirements may develop towards 2020** - for example :
Potential for market actors to become more open / flexible to the demand-side offers / services which customers are able to make.
Emerging practical challenges and commercial issues around the inter-action and 'hierarchy' of different demand-side services – from both the view-point of different market actors - and customers.
Major pluses and minuses to your business of more Heat Pumps, Electric Vehicles and PV connecting ? Will these technologies support greater DSR value developing into the early 2020's for your business ?
International experience - any relevant major lessons for your business ?

Annex 8 - Market Actor Need for Demand-Side Services - and the customers who provide these.

I - NG Balancing Services which may be provided by DSR[85].								
Market Service	**Notice Period / Speed**	**Duration**	**Minimum Load**	**Time of Day / Year**	**Location Specific**	**Communication & Monitoring**	**Indications on Value**	**2012 Customer Participation**
Firm Frequency Response (FFR). Firm availability of 'Dynamic' and/ or 'Non-Dynamic' frequency response in 'nominated' periods. Aim is to manage system frequency within statutory & operational limits (1) in the event of a loss of either generation or demand and (2) to correct short-term frequency	Dynamic - Automatic / Instant. **Primary Response -** delivered over 2-10sec timeframe sustained for up to 30secs. **Secondary Response -** delivered within 30secs & sustained for up to 30min. **High Frequency Response -**	Non-Dynamic Response: At least 10 minutes May be tripped 10-30 times pa for a low frequency event (depending on frequency relay threshold setting)	Minimum 10 MW of energy which can respond, although volumes less than this permitted if evidence that the service can grow to 10MW+	Any. Daily.	Location is a secondary factor in the assessment of a frequency service - although it may be taken into account given network constraints and any subsequent restrictions on the use of frequency response	Operational metering / Measurable Able to provide both : **'Dynamic' Frequency -** Automatic / instant changes to load in response to second-by-second changes in system frequency. **'Non-Dynamic' Frequency** – service triggers at a pre-set frequency variation (eg 49.7 Hz).	Frequency Response spend (Total – 2011/12) - £193m Indicative payments £50-£60/kW/pa split between a tendered Availability, Holding and Utilisation fee.	Dynamic Response: (Large B-M generators required to provide 'Mandatory' frequency response). Both BM & Non-BM providers may participate in the Firm Frequency Response market operated through a Framework Agreement -with monthly tender for single or multi-month contracts Demand Examples. **Dynamic –**

[85] Balancing Services can be provided to National Grid by : Large Generators (BM Units) ; Embedded Generation ; Back-up Generation ; Large Loads (demand reduction) ; Aggregation of smaller loads e.g. water plants ; heating / chilling industrial units.

Sources : National Grid email correspondence. June 2012. Plus, National Grid website - publications and presentations. Also, report for DTI. URN 06/1432. 'Reducing the Cost of System Intermittency Using Demand Side Control Measures'. 2006. IPA Consulting, E-Connect Ltd & Martin Energy.

variations due to delay in Balancing actions taking effect. Demand *reduces* to balance falling frequency. Demand may also be *increased* to increase frequency (within 10 seconds).	delivered over 2-10secs timeframe, sustainable indefinitely. **Non-Dynamic** Within 10- 30 seconds				energy these might impose			3-5 MW of commercial heating load. OpenEnergi (formerly RLTEC). Frequency response contract with National Grid. Heating & Ventilating Units across 200 Sainsbury Stores – March 2011. **Non-Dynamic –** Not at present.
Frequency Control by Demand Management (FCDM). Frequency control by automatic interruption of demand customers to support management of low frequency. Low frequency relays at providers' sites automatically 'trip' demand if frequency falls below a pre-set point – eg 49.7Hz.	Within 2 seconds (i.e. via trip relay).	At least 30 minutes May be tripped 10-30 times pa for a low frequency event	3 MW (can aggregate at same site).	Any	Location is a secondary factor in the assessment of a frequency service - although it may be taken into account given network constraints and any subsequent restrictions on the use of frequency response energy these might impose.	Operational metering / relay measurement	Maximum potential value in line with Firm Frequency Response (FFR). However FCDM is a 'non-firm' service so actual value achieved may fall short of the firm service offered by 'Firm Frequency Response'.	Procured bilaterally. Aggregated. Typically, can expect to be interrupted around 10-30 times p.a. Potential market size – 500+MW – volume of contracts struck - dependent wholly on economics when compared with other response services. Demand Examples –150 MW@49.7 Hz.

Market Service	Notice Period / Speed	Duration	Minimum Load	Time of Day / Year	Location Specific	Communication & Monitoring	Indications on Value (2009 unless otherwise stated)	2012 Customer Participation
Fast Reserve Demand reduction (or increase in generation) to manage large and rapid rates of change - e.g. for TV 'pick-ups' ; Autumn & Spring 'shoulders'.	Begin delivery within 2 minutes (at rate >= 25 MW / minute)	Sustain for 15 mins minimum	50 MW (can aggregate).	Any. Daily (during rapid changes in demand).	Location is a secondary factor in the assessment although it may be taken into account given network constraints and any subsequent restrictions on the use of frequency response energy these might impose.	Operational metering	Availability payment - £44k/MW pa Usage payment - £6k/MW pa (For BM generators - £/MWh as per BM bid-offer prices). Plus possible Optional 'enhanced' service fee if can match run-up / run-down rates.	Fast Reserve spend (total 2011/12) - £92 million. Tendered (monthly) and / or bi-lateral - dependent on service-provider characteristics. Can be 'firm'- or 'optional'service under a framework agreement. Requirements vary significantly by time of day. Peak requirements for the service occur late evening and can exceed 1000 MW. A year round 24/7 'average' indicative requirement would be in the range 100-500MW Example - ~250 MW tele-switched storage heater load.

Market Service	Notice Period / Speed	Duration	Minimum Load	Time of Day / Year	Location Specific	Communication & Monitoring	Indications on Value (2009 unless otherwise stated)	2012 Customer Participation
Short Term Operating Reserve	Ideally within 20 minutes – but fully available within 4 hours.	At least 3 times per week. Fully available for at least 2-hours. Ideally 3-4 hours.	3 MW Up to 50-80 hours p.a. (windows)	Either side of morning & evening peaks. All year round. Weekdays & weekends	Location is a secondary factor in the assessment although it may be taken into account given network constraints etc.	Operational (Real-time) Metering	Availability payment - ~£22k/MW pa Usage payment - ~£12k - £18k pa variable (for 1 MW 50 – 80 called hours pa) (For BM generators - £/MWh as per BM bid-offer prices). Average STOR bidder offer prices in 2010-11 were : Availability - £9/MWh Usage - £250/MWh Average STOR bidder offer prices in 2011-12 were : Availability - £8/MWh Usage - £225/MWh	STOR spend (total 2011/12) - £98m 'Committed' or 'flexible' contracts. Contract length – one year plus (and potentially up to 15 years although maximum contract length currently offered is 2 years). Examples – Industrial process interruption Switch to on-site back-up generation
Demand Management	Flexible	Must provide service across a minimum of 2 consec settlement periods (i.e. one-	25MW	Morning Demand Peaks and Evening Demand Peaks	Location is a secondary factor in the assessment although it may be taken into	Operational metering	N/A	None

		hour).			account given network constraint s etc			
Transmission Constraints Short-term measures to alleviate local power flows / constraints during planned maintenance on Transmission network		Short-term or long-term DSM responses – instead of temporary network constraint measures (e.g. FACs, SVCs).			Yes		Transmission constraint spend (total 2011/12) - £324m	Currently no DSR participaton. National Grid's costs of managing transmission constraints have been increasing with more wind commissioning, especially in Scotland – and associated upgrade works of the transmission system. National Grid seeks to reduce constraint costs via locational contracts. The characteristics of constraints tend to require a service for extended periods - every day, possibly for weeks or months – and this could prove disruptive for a DSR provider. Moreover, constraints may be one-offs – or not re-occur for a number of years – so may offer a DSR provider little revenue continuity.

II – Deferred or Avoided Transmission Network Use of System Charges (TNUOS) from DSR								
Market Service	**Notice Period / Speed**	**Duration**	**Minimum Load**	**Time of Day / Year**	**Location Specific**	**Communication & Monitoring**	**Indications on Value** (2011)	**2012 Customer Participation**
TRIAD avoidance - aims to suppress winter peak demand - and so to enable deferred network re-inforcement – and thereby keep down TNUOS charges. TRIAD avoidance thus offers scope for I&C customers to avoid some peak-related transmission charges (TNUOS). The annual £/MW TNUOS network charges payable by licensed suppliers to National Grid, are based, in part, on a supplier's maximum load in each of 14 zones. TNUOS charges for the year ahead, are based on maximum demand / load - averaged over the three winter peak half-hours – the TRIAD. TRIAD-related TNUOS charges therefore seek to create an incentive to curtail peak demand.	~Day Ahead ?	One-hour - at three winter peaks – 17.00h – 18.00h	>100 kW (Most likely)	Yes – three winter peak demands (but may be 10-20 'warnings').	Yes – charges vary by 14 zones.	Half-hourly settlement.	**Demand Tariff for H-Hly metered customers**: applied to average half-hourly metered demand over the three TRIAD (winter peak) half-hour periods. TNUOS Charges vary according to geographic zone **Locational Charge** 2012-13. North Scotland - £10.74/kW London - £31.17/kW. **Non-Locational 'residual' element** - £22.83p/kW in 2012-13 (regardless of zone).	Transmission demand charges are payable by suppliers. Split into 14 geographic zones. Generally, lower in north and higher in south. ~Three-quarters of £1.7 billion annual transmission network use of system charges (TNUOS) are levied from Demand (G:D T-charges split is 27:73%). Of this, approx £370million is recovered from Half-Hourly metered demand customers who are eligible to participate in the TRIAD avoidance mechanism. **For half-hourly settled customers** (so >100kW), customers can agree for the supplier to 'pass-through' transmission charges directly to them. In effect, this is akin to an opt-in Critical Peak Rebate – available to half-hourly settled 100 kW-plus I&C customers, if they so choose . **For Load Profile 1-8 customers** : an **Energy Consumption Tariff** is charged by transmission

								networks to each supplier in each zone (as per settlement) during the period 16.00h-19.00h each day. **Example - 2012-13 Energy Consumption Tariff :** North Scotland Zone – 1.48p/kWh Southern Zone – 4.34p/kWh

III – Deferred or Avoided DNO Investment from DSR. See Annex 1 for Examples.								
Market Service	**Notice Period / Speed**	**Duration**	**Minimum Load**	**Time of Day / Year**	**Location Specific**	**Communication & Monitoring**	**Indications on Value** (2011)	**2012 Customer Participation**
EHV / HV Networks Fault Response – bi-lateral arrangement between DNO and customer(s) or aggregator.	~3-4 hours	Possibly, up to several weeks	? 1 MW (but can be aggregated).	Any	Yes	Half-hourly metering	SF Guesstimate ~£40-60k/MW/pa (so, £40-60/kW/pa)	Aggregated I&C Load – see Annex 1 for practical examples.
Low Voltage Networks Thermal constraint management				Winter	Yes	Teleswitch		Example – Economy 7
Distribution Use of System Charges (DUOS) – payable by suppliers to DNOs to allow cost-recovery by a DNO of the fixed and variable costs of network investment, re-inforcement,	Customer aware of ToU charges	3 hours	100 kW +	Mostly (but not only) winter.	No	Half-hourly meters	See DNO Annual Statement of Charges for the Use of the Electricity System (each DNO web-site). DUOS charges, for all half-hourly customers	**EHV directly-connected Half-Hourly customers** – DUOS charges passed-on by supplier. Super-red time bands charged at winter weekday evening peak across all DNO areas. (In London, super-red time bands apply both during winter evening peak hours – 16.00h-19.00h Nov-Feb *and* summer 11.00-14.00h June-August). **Half-hourly customers connected at any**

maintenance, repair and operation. A generic charging methodology - the **CDCM – Common Distribution Charging Methodology** – introduced in April 2010. **DUOS charges** typically include a **daily fixed cost of pence / customer** plus a **p/kWh energy-related charge**. Other costs (e.g capacity-related) on basis of customer load profile. **Seasonal Time of Day Tariffs** – for 117,000 half-hourly metered and settled customers. **All other customers -** some limited day / night tariff s - subject to the meter Load Profile.						No - Load Profile according to meter-type No - Load Profile according to meter-type	include (inter al) : a fixed charge per customer per day (standing charge); a separate capacity-related charge – and 3- (seasonal) p/kWh unit rates. These elements vary, depending at which network voltage the customer is connected.	**voltage** – DUOS charges passed –on by supplier. A seasonal 3-part time of day element incorporated in DUOS charges. Red, Amber and Green periods. **Load Profile 5-8 Customers** (166,000) – 2-part day-time and lower night-time p/kWh unit charge payable by supplier. **Load Profile 1-4 Customers** (29 million) – connected at Low Voltage. p/kWh unit DUOS charge payable by supplier – plus a night-rate for Econ 7 & off-peak customers (LPs 2 & 4).

Market Service	**Notice Period / Speed**	**Duration**	**Minimum Load**	**Time of Day / Year**	**Location Specific**	**Communication & Monitoring**	**Indications on Value** (2011)	**2012 Customer Participation**
Non-Firm Connection Agreement Connection charges allow cost-recovery by DNO of any necessary works / new capital assets to connect new generation or demand to its network to the requested 'required capacity' (kVA). 'Non-firm' connection agreement may allow customer to pay lower charges.			Likely to be half-hourly customers (so 100kW+). – but could also be 'community-level' schemes.	Winter peak – but not just.	Yes	Communications and metering	'Discount' against published DNO connection charges. Lower DUOS charges.	Customer has non-firm connection agreement whereby load can be curtailed where network constrained, in return for a lower initial up-front connection payment – and lower ongoing DUOS charges).

IV – Supplier Demand Management Schemes via Retail Tariffs – See Annex 1 Examples								
Market Service	**Notice Period / Speed**	**Duration**	**Minimum Load**	**Time of Day / Year**	**Location Specific**	**Communication & Monitoring**	**Indications on Value** (2011)	**2012 Customer Participation**
Suppliers seek reduced operating costs through management of (1) wholesale energy procurement risk and (2) imbalance risk. 117,000 100kW+ customers: ~48% of all electricity consumed (155TWh p.a.) 166,000 Load Profile 5-8 customers: ~5% of all electricity consumed (~17 TWh p.a.)		ToU and seasonal retail tariffs over a 24 hour period.	Half-hourly -so 100kW plus Load Profiles 5-8.	Yes	No	Half-hourly meters for 100kW+. LP5-8 meters for others	~60% of an I&C customer's total end-bill is likely to be energy related.	**I&C Customers** Half-hourly metered and settled customers - will be on a variety of fixed and flexible energy management contracts – & which may incorporate some fairly granular time-varying pricing – peak / off-peak, day/ night, seasonal elements. Load Profile 5-8 customers - likely to be on a somewhat more limited range of day/night/ seasonal tariffs – unless half-hourly metered. Example : Government Procurement Service procures around 4% (~14TWh p.a.) of all electricity consumed. GPS offers public bodies opportunity to access power in the half-hourly and non-half-hourly wholesale markets – incl. via 10MW hourly 'base-load' blocks – 19.00h-07.00h.

Market Service	**Notice Period / Speed**	**Duration**	**Minimum Load**	**Time of Day / Year**	**Location Specific**	**Communication & Monitoring**	**Indications on Value** (2011)	**2012 Customer Participation**
Load Profiles 1-4 – Small Business and Household Customers Economy 7 / Off-Peak customers : Load Profile 4 - 0.5 m customers Load Profile 2 Customers - ~5 million.	Instant – but staggered switching	Midnight to 07.00h	1-7 kW	Yes	Customer pays a lower Econ 7 night-time retail tariff – irrespective of their location. However, radio-teleswitch can in fact be switched by location - or not – as required.	Radio Teleswitch for ~ 2 million of the 5.5 million total LP2 & LP 4 meters. Discussion about Radio Teleswitch being maintained beyond 2017.	Supplier shares the benefit with their customers – of the customer consuming most of their electricity overnight - when wholesale prices are lower – via a lower overnight retail tariff. Customer may however pay a higher day-rate than a standard day rate (for fixed cost recovery). Overnight tariff therefore may be best suited to customers who have more load running overnight (eg storage heaters) to offset disbenefit of a possible higher day-rate.	LP 1 & 3 meters are 'unrestricted'. LP 2 & 4 meters can be 'switched' and/ or are 2-rate - for those customers on an Economy 7 or equivalent overnight tariff. **Load Profile 3&4 customers** – ~2 million small & medium enterprises. **LP 4 customers** – ~0.5m customers. May consume ~3 TWh p.a. as off-peak night-time units (i.e. at most ~ 10% of all LP 3&4 units combined (~35 TWh). **Load Profile 1&2 customers** – mainly households and small business. 27 million customers total. 22 million LP1 and **LP 2 customers –** ~5 million. May consume ~10 TWh as off-night-time peak units (so, ~9% of all household units).

Sustainability *First*

Sustainability *First* was set up to develop new approaches to sustainability. Its primary focus is on policy and solutions within the UK, but draws on experiences and initiatives both within and outside the UK.

Sustainability *First* develops implementable ideas in a number of key policy areas – notably, energy, water and waste - where it can make a difference. It undertakes research; publishes policy and discussion papers; organises high level seminars and other events. Sustainability First is a registered charity.

Sustainability *First*'s associates are: Gill Owen and Judith Ward. Maria Pooley is Sustainability *First*'s research officer.

Sustainability *First* is a registered charity number 107899.

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Sustainability *First*