

**Sustainability *First***

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

**Paper 1**

**GB Electricity Demand –  
Context and 2010 Baseline Data**

**by Gill Owen, Judith Ward and Maria Pooley  
Sustainability First**

**October 2011**

**Published by Sustainability First**



**Sustainability *First***

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

**Paper 1**

# **GB Electricity Demand – Context and 2010 Baseline Data**

**Prepared for the Smart Demand Forum**

**by Gill Owen, Judith Ward and Maria Pooley  
Sustainability First**

**October 2011**

Published by Sustainability *First* – [www.sustainabilityfirst.org.uk](http://www.sustainabilityfirst.org.uk)

**Sponsored by** : BEAMA ; British Gas ; EDF Energy ;  
E-Meter Strategic Consulting; E.ON UK ; National Grid ; Northern Powergrid ;  
ScottishPower Networks ; UK Power Networks.

**Smart Demand Forum Participants** : Sponsor Group ; Energy Intensive Users Group ;  
Consumer Focus ; Which? ; National Energy Action ; Brattle Group ; Lower Watts  
Consulting ; DECC ; Ofgem.

**Copyright © Sustainability First, 2011.**



## Preface

### Sustainability First

Sustainability First is a UK environment 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](http://www.sustainabilityfirst.org.uk).

Since 2006, Sustainability First has produced a series of 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<sup>1</sup>.

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

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<sup>2</sup>. Work is coordinated through a Smart Demand Forum whose participants include colleagues from consumer bodies, DECC and Ofgem, as well as sponsor group members<sup>3</sup>.

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.

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

---

<sup>1</sup> Earlier Sustainability First smart meter papers are available on the website – [www.sustainabilityfirst.org.uk](http://www.sustainabilityfirst.org.uk)

<sup>2</sup> Sponsors include : **BEAMA ; British Gas ; EDF Energy ; E-Meter Strategic Consulting; E.ON UK ; National Grid ; Northern Powergrid ; ScottishPower Networks ; UK Power Networks.**

<sup>3</sup> **Smart Demand Forum includes sponsor group members, Energy Intensive Users Group, Consumer Focus, Which ? National Energy Action, DECC and Ofgem.**

The work programme is being delivered through the Smart Demand Forum, through annual Northern Powergrid stakeholder events, and through a series of published papers and other materials. The project is run by Sustainability First<sup>4</sup>.

### **Key themes for the project include:**

- **Customer Response and Consumer Issues** - Key issues for successful and cost-efficient demand-side participation of consumers (household, industry, commercial and public sectors). This will include options 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 also 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. Approaches and incentives for integrating the demand side into the wider 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 to be published in the first year of the project will be:

**Paper 1 - GB Electricity Demand - context and 2010 base-line data**

**Paper 2 – GB Electricity Demand 2010 and 2025 – scope for demand reduction and flexible response**

**Paper 3 - What demand-side services could GB customers offer?**

**Paper 4 - What demand-side services can provide value to the electricity sector?**

---

<sup>4</sup> 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.

Topics for papers in future years are likely to include:

- **Alignment of Commercial Drivers and Regulatory Incentives**
- **Public Policy, Business Models and Realisation of Electricity Demand-Side**
- **Distributed Generation**
- **Active I&C Customers**
- **Active Household and Micro-business Customers**
- **Consumer Issues**
- **Longer-Term Demand-Side Realisation and Innovation**

## **Preface**

### **1. Introduction**

## **Part 1 – Context for GB Electricity Demand**

- 2. The centrality of the customer in the demand side**
- 3. Commercial and regulatory considerations for the demand side**
- 4. UK and EU policy context for GB electricity demand**
- 5. Electricity demand side definitions**

## **Part 2 - Baseline Data for GB Electricity Demand 2010**

- 1. Overview**
- 2. UK electricity end-use by key economic sector**
- 3. GB demand and the electricity system**
- 4. Transmission / Distribution interface – distributed generation**
- 5. Customer Expectation - system security and reliability**
- 6. Variability of demand**
- 7. How load is met – the need for flexibility**
- 8. Demand-side flexibility**
- 9. GB load management 2010**
- 10. GB despatchable and deferrable load**
- 11. Valuing system flexibility and avoided peak-load**
- 12. What is assumed today about flexible GB demand in 2020?**

## **Glossary**

## **Data Annexes**

- Annex 1 - Regional consumption data**
- Annex 2 - Estimated electricity end-use by economic sector**
- Annex 3 - Historic trends in electricity consumption**
- Annex 4 - Heat and non-heat uses of electricity - and of other fuels**
- Annex 5 - UK electricity capacity and supply by fuel**

**Index of figures**

Figure 1 Sector breakdown of electricity consumption in 2010.....	29
Figure 2 UK Final electricity consumption for industry in 2010 .....	30
Figure 3 UK Final electricity consumption in the services sector 2010.....	31
Figure 4 Volumes of metered demand by economic sector, year to September 2011.....	36
Figure 5 Summer and winter daily demand profiles in 2010/2011. ....	46
Figure 6 Annual load duration curve for 2010/2011. ....	46
Figure 7 Weekly maximum and minimum demand in 2010/2011 .....	47
Figure 8 GB Electricity demand profiles, weekday and weekend.....	47
Figure 9 - Forecasting Electricity Demand – Royal Wedding Day. 29 April 2011.....	49
Figure 10 - Royal Wedding 29 April 2011. Demand Outturn and Frequency .....	49
Figure 11 UK Electricity supplied by fuel in 2010.....	50
Figure 12 Average industrial/commercial electricity consumption per meter point in 2009 (KWh).....	77
Figure 13 UK electricity consumption 1980-2010 .....	80
Figure 14 UK Electricity supplied by fuel in 2010.....	87

**Index of tables**

Table 1 GB Generation Capacity and Electricity Demand in 2010.....	28
<b>Table 2 UK Domestic Electricity. Standard and off-peak units supplied. 2010.....</b>	<b>32</b>
Table 3 Estimated UK Domestic Electrical Appliance End-Use 2009 (minus heating and hot water) .....	33
Table 4 GB Half-Hourly and Non-Half Hourly Annual Energy Consumption Recorded (TWh) at September 2011.....	35
Table 5 GB electricity winter profile – maximum & typical weekday profile.....	44
Table 6 GB electricity summer profile – typical weekday .....	44
Table 7 Estimated contribution by customer type to peak-load .....	45
Table 8. System Operator. Balancing Services/ Operating Reserve for Energy .....	54
Table 9 Supplier Demand Management .....	55
Table 10 Supplier Demand Management – Retail Tariffs.....	56
Table 11 Distribution Networks.....	58
Table 12 Estimated contribution by customer type to peak-load .....	63
Table 13 Estimated potential demand from heat pumps in 2020 by time of day blocks.....	71
Table 14 Estimated UK domestic electricity consumption by end-use 2008 .....	78
Table 15 Estimated UK services sector electricity consumption by end-use – 2008 .....	79
Table 16 Estimated industrial electricity consumption by end-use - 2008.....	79
Table 17 UK Electricity consumption- 1980-2010.....	81
Table 18 Estimated UK Gas and electricity consumption by end-use by sector 2008.....	83
Table 19 Estimated UK domestic energy consumption by fuel - 2008.....	84
Table 20 Estimated UK service sector energy consumption by fuel – 2008.....	85
Table 21 Estimated industrial energy consumption by fuel – 2008.....	86

## 1. Introduction

This paper is the first in a series for the Sustainability First project ‘**GB Electricity Demand – *realising the resource***’.

The paper is in two parts.

### **Part 1 – Context for GB Electricity Demand.**

Part 1 sets out a high level summary of key policies and issues affecting the outlook for successful development of the GB electricity demand-side, including:

- Customer, commercial and regulatory considerations
- UK and EU policy context for GB electricity demand

Part 1 concludes with key electricity demand-side definitions.

### **Part 2 – Baseline Data for GB Electricity Demand 2010**

Part 2 pulls together key data from published sources about GB electricity demand in 2010. This includes data on the electricity used by different customer groups, on recent demand growth, and on what is known about peak and off-peak usage. Part 2 also gives a high-level outline of the present role of the electricity demand-side in the GB electricity market today and prospects for today’s customers to play a greater role.

The aim of Part 2 is to:

- Provide a resource on GB electricity use today
- Improve on present understanding of how electricity is used in 2010.
- Establish a well-informed base-line for the GB Electricity Demand project – from which it will build in looking forward to the 2020’s.
- Identify important knowledge gaps or missing data regarding particular aspects of GB electricity demand today – e.g. its key uses, characteristics and elasticities, its current value to different market actors, its potential to be despatched or to be flexible at different times.
- Paint a high level overview of the role that the electricity demand-side plays in the electricity market today – both to inform the project going forward - and also to inform the forthcoming Ofgem Electricity Systems Framework and DECC Electricity Systems Policy.

## **Part 1 – Context for GB Electricity Demand.**

### **2. The centrality of the customer in the demand side**

Unlike the supply side of electricity, where delivery is dependent upon the actions of a relatively small number of actors (essentially in GB fewer than 50 entities, taking into account retailers, networks, major generators, system operator) the development of an active and effective demand side will be dependent upon the actions of millions of customers. If customers are not willing to participate then there will be no demand side. And, unlike those on the supply side, for whom this is their core business, being an active electricity customer is not likely to be high on the list of priorities for most customers.

So key questions will be:

- how to motivate customers to engage in delivering a more active demand side
- what level of incentives will be required to engage customers
- how can retailers, networks and others (e.g. aggregators) make it easy for customers to participate
- what forms of demand side participation by which customers are cost effective in comparison to supply side solutions

Customers are not a homogenous group. There is a need to differentiate clearly between:

- Customer segments – industrial, commercial, public sector and households.
- In terms of the business sector, it will be important to consider the different issues for large, medium and small customers. The smallest business customers may be more similar to households in many respects than they are to other business customers.
- Different types of households in terms of property size, heating type, number of occupants, income levels etc.
- Customer location will also be important for some forms of demand side potential for some purposes (notably the scope for demand response to deliver value to distribution networks)

The project will examine key issues for successful and cost-efficient demand-side participation, including tariffs and incentives. This will include the responses of different groups of consumers (household, industry and business) to options provided through the LCNF trials (e.g. tariffs, remote control of appliances, technologies such as microgeneration, electric vehicles etc.) and other similar initiatives in the UK and elsewhere. Response means both take-up of options and behavioural responses to options that are taken up.

Clearly a very major issue will be the extent to which customers will be willing to sign up to new tariffs and agreements to provide demand response. Central to this will be the implications for customer bills.

For households there will also be **specific** considerations for the fuel poor and / or vulnerable customers, including take up, potential distributional impacts and whether any new safeguards will be required.

A further area will be issues and principles about pricing approaches which may be more cost-reflective (to some degree) and possible impacts on different customer groups, including on pricing across - and between – economic sectors – and likely characteristics of prospective winners and losers.

**In this paper we are just setting out some of the key customer-side issues. These will be explored in more detail in subsequent papers.**

### 3. Commercial and regulatory considerations for the demand side

A key focus of this project will involve analysis of the major commercial policy and regulatory issues, including any significant market failures, and identifying measures either in the short or longer-term, needed to unlock GB demand-side resource. At this initial stage of the project, this section simply aims to scope out some of the likely issues to be addressed, drawing from practical experiences of the LCNF Trials and other experience in the UK and elsewhere.

Commercial and regulatory issues are seen as closely intertwined, because regulation shapes many of the commercial arrangements and the need to re-shape commercial incentives can drive the case for changes in regulation. Policy can be one step removed from regulation but can often also have a direct impact on commercial incentives. Thus, whilst there will be some issues that are purely commercial, or purely regulatory or purely policy, many will impinge in two or more of these spheres. This section of this paper considers the commercial and regulatory issues. The broader policy issues are summarised briefly in Section 4 below and will be covered in more detail in subsequent papers.

Commercial incentives and regulatory arrangements will affect different market actors in the value chain and shape what is practically ‘achievable’ in terms of the demand side. The key issues and barriers will vary for different market actors and in different time-scales – operational (short-run) and investment (both today and into the 2020s).

On the commercial side, issues are likely to include:

- available returns on investment
- demand-side price transparency
- who pays and who benefits and how costs and benefits are to be shared
- the nature of commercial agreements between market actors
- the role of third parties,(DNOs, ESCOs, aggregators)
- information-sharing likely to be necessary between parties.

On the regulatory side, issues are likely to include:

- returns on assets
- statutory codes,
- charging principles & methodologies
- Network and System Operator Price Controls and incentives in price controls,
- settlement issues

To elaborate on some of these issues:

### **Incentives for different actors in the electricity value chain**

- There may be little incentive to reduce costs where existing costs can be passed in large part through to someone else - e.g. networks able to pass costs to suppliers (e.g. via use of system charges, albeit networks incentivised to keep-down costs via their periodic price controls), and which suppliers can pass to end-customers; generators pass through power purchase costs to suppliers and on to end-customers. This lack of incentive could apply particularly if reducing costs results in other costs (actual or opportunity costs – e.g. management time, diversion of effort from more profitable activities etc.) .
- Individual market actors may have little incentive to deliver cost-savings to the benefit of the overall electricity system where the benefit may largely fall to other players – or, worse, impose a new cost on them in facilitating delivery to others.
- If costs produce revenues in excess of those costs (i.e. profit) - then there will be little incentive to reduce them – e.g. for networks this will be affected by regulatory treatment (e.g. a larger RAB (regulated asset base) produces a proportionately larger return and vice versa); for suppliers this will depend upon the relationship between wholesale costs and retail prices.
- Differences between integrated and non-integrated generators. For generators who are vertically integrated with supply businesses, selling fewer units may not be unduly problematic if the revenue can be made up in other ways (e.g. by improved efficiency by increasing market share, or developing new energy services). However, stand-alone generators whose only source of revenue is to sell units of electricity, may have little interest in selling fewer units (unless in the short-run to hedge risk).

### **Competition for demand response**

- Third Parties – Aggregators and ESCOs - could bring new value, competition and innovation in Demand Response, but also, potentially, some risk to others in the value chain, plus complexity in terms of benefit-sharing and multi-party agreements.
- There may be competition for demand response services between different actors in the value chain – e.g. networks, retailers, and aggregators<sup>5</sup>.

---

<sup>5</sup> National Grid. Operating the Electricity Transmission Networks in 2020. Update. June 2011

**Complexity, co-ordination and need for agreements between different parties**

- Actions by some in the value chain can create impacts for others and it is not clear how information would be shared and in what timescales; the needs for co-ordination could become increasingly important.<sup>6</sup> For example, a retailer or aggregators might contract with a group of customers in a small geographic area to provide demand response via electric vehicles or heat pumps for wholesale market benefits. However, if delivered in a small geographic area this could have a significant impact on the distribution network's ability to cope with peak demand, if there is a mismatch between peak demand periods for network and wholesale purposes. Eventual agreement on information-sharing may be essential to avoid the risks of financial exposure to unpredictable or unknown demand-response arrangements put in place by others in the value chain.
- Industry codes and agreements between all in the value chain (customers, suppliers, networks, aggregators, system operators) will need to evolve and adapt. This includes in respect of embedded generation or microgeneration (when exporting can have an equivalent effect to a reduction in demand).
- The economic and practical complexities of many millions of agreements to deliver household and small business demand response where each agreement has a small value. Aggregation by suppliers themselves, or, by other market actors will be necessary. Third-parties may contract with others (including customers) to deliver demand-response. The benefit to each contracting party would need to be sufficient to make it worth-while for each to participate and invest in automated equipment etc.

**Establishing value and realising value – including regulatory treatment**

- Our 2010 paper<sup>7</sup> drew high level initial conclusions that for electricity, in broad terms:
  - potential demand-side savings associated with reduced wholesale costs in the electricity market were likely to be greater overall than the overall potential for avoided-cost savings from demand response in the networks<sup>8</sup>. However, significant location-specific cost-savings could be available on individual parts of the networks via demand-response - and increasingly so going forwards.
  - the major cost-savings for suppliers from demand response will be achieved in reducing what they pay to other parts of the energy-system supply-chain – i.e. reduced wholesale energy purchase, better contract match, and reduced charges (potentially for use of networks, system balancing), and, potentially, from reduced environmental charges.
  - value of potential network savings from avoided-cost at peak is likely to increase post-2020, given significantly more distributed generation, and as

---

<sup>6</sup> National Grid. Operating the electricity transmission networks in 2020. Update. June 2011.

<sup>7</sup> Owen G & Ward J. Smart Tariffs and Household Demand Response for Great Britain. Sustainability First. March 2010. Pp 41-42.

<sup>8</sup> Given that, in very general terms, wholesale costs comprise ~50-60% of the end bill and networks comprise around ~20%.

responsive electricity load grows significantly (e.g. electric vehicles, off-peak electric heat).

- Demand response (either peak or overall demand reductions) will need to be firm - or very largely predictable - for either network or supplier procurement costs to be avoided – short-run operational and long-run investment. This will almost certainly require some form of automatic load-control or enforceable contract. For example, an aggregator / ESCO may take responsibility for reducing peak or overall demand<sup>9</sup>. Household-level DSM agreements are common in the US. For GB, questions arise as to the nature and duration of customer agreements likely to be needed for firm or predictable delivery and aggregation<sup>10</sup>: third-parties may look for long-term agreements to prevent stranding of any equipment or measures they install; customer acceptability of automatic control; and, the potential need for customer protections.
- Some demand response could translate into savings of load-related network reinforcement costs. This should feed through into allowed revenues under a price-control and subsequent distribution network charges, but there may be a time-lag until suppliers are able to obtain the direct benefits of any savings they create for DNOs. The 2009 distribution price control review (DPCR5) began the process of neutralising incentives for networks as between investment in peak-assets and demand-side actions.
- Transparent pricing signals on the demand-side, for example through electronic platforms, exchanges, auctions and tenders, are likely to be important tools for the future in helping demand-side providers to identify what value may be available for providing demand response solutions into different parts of the market in a variety of time-scales.
- Under the present profiled settlement arrangements, the financial benefits from demand-side response initiated by an *individual* supplier will be socialised among *all* suppliers, for all but the very largest users. Suppliers could lose twice-over: by failing to capture the full benefit of their own investment; and, by creating reduced costs for their competitors, creating a disincentive to supplier demand-side investment. As smart meters are rolled-out, accurate settlement for small users will become feasible, albeit potentially involving additional costs in respect of data handling and billing.

**In this section we have simply set out some key commercial issues at a very high level, including those identified in the Sustainability First March 2010 paper<sup>11</sup>. In particular, identifying ways in which different market actors can equitably be incentivised to deliver demand-side benefits, will be key. These and other commercial and regulatory issues will be explored in more detail in subsequent papers.**

---

<sup>9</sup> For example, perhaps via load-management contracts, time-of-use tariffs, or, in extremis, critical-peak pricing agreements.

<sup>10</sup> One example might be where uncoordinated actions on the demand-side could create new imbalance risk, exposing market actors to costs over which they may lack direct control.

<sup>11</sup> Owen G & Ward J. Smart Tariffs and Household Demand Response for Great Britain. March 2010.

#### 4. UK and EU policy context for GB Electricity Demand

The policy landscape impacts on current and future values for demand response, demand reduction, flexibility, and longer-term electricity demand growth.

GB electricity demand through to 2020 will be shaped by UK and EU policies for:

- Power sector decarbonisation
- Decarbonisation of heat
- Energy efficiency
- Energy affordability
- Electrification

#### UK and EU Targets – Implications for Electricity Demand Side

Binding targets and related policies are driving the move to low-carbon electricity, renewables, greater electrification and a need for greater flexibility in the electricity system.

- **Climate Change Act 2008 and 4<sup>th</sup> Statutory Carbon Budget 2023 – 2027.** CCC anticipate power-sector emissions down to ~50gCO<sub>2</sub>/kWh by 2030.
- **EU Renewables Target** – UK share of 15 % Renewables by 2020 - of which 26-30 GW wind by 2020 (i.e. about 30% of total supply). CCC May 2011 Renewables Review assumes ~ 40% wind (40 GW) by 2030.
- **EU ETS** – carbon emissions are capped upstream under Phase III until 2020 on an EU-wide basis at a 20% reduction, with EU ETS Allowances (EUAs) allocated on that basis. Unless the EU ETS cap is tightened - or unless Allowances are retired early – measures to reduce electricity usage will not result in any additional carbon savings, due to the arrangements for EU-wide carbon accounting<sup>12</sup>.
- **Large Combustion Plant Directive / Industrial Emissions Directive** – drive 2012 and 2016 closures of older flexible fossil plant, which will drive up current cost of providing system flexibility.

#### Electricity Supply-Side Policies and Measures – Implications for Electricity Demand Side

**Carbon-Price Support** – Finance Act 2011 introduced a UK carbon price-floor which will serve to accelerate the closure of certain flexible fossil plant. The cost of flexible provision to the GB electricity market will therefore increase. Higher prices for fossil generation will increase the pre-2020 value for both electricity demand response and for electricity demand reduction, increasingly so towards 2020, as more wind and nuclear also start to increase system flexibility requirements.

---

<sup>12</sup> CCC foresees EU convergence at 30% by 2030.

**Energy White Paper and Electricity Market Reform<sup>13</sup>** (EMR) – The Energy White Paper and EMR proposals published in July 2011 aim to increase incentives for major new low-carbon plant. One strong strand of comment had been to urge government to use the opportunity of EMR to create a level playing-field for the demand-side alongside supply side investment. The EWP sets out several ways in which Government proposes to consider the electricity demand-side going forwards, including in EMR. It indicates:

- **An Electricity Efficiency assessment** - ‘in the coming year’ on whether to take further steps to improve the support and incentives for the efficient use of electricity<sup>14</sup>.
- **An Electricity Systems Framework** – from Ofgem in Spring 2012 and an **Electricity Systems Policy** – from DECC in Summer 2012 – which will consider the overall framework through which supply and demand is balanced – including **the role of DSR**, storage, interconnectors and development of smarter grid<sup>15</sup>.
- **FIT CfDs (Contracts for Difference)** – long-term contracts designed to incentivise low-carbon plant with large fixed costs but comparatively low operating costs in the wholesale market (base-load, intermittent, variable). There is no expectation in the EWP of electricity demand-side access to wholesale market long-term contracts such as FIT CfDs.
- **Capacity Mechanism** - new capacity contract arrangements from 2019 to deliver ‘resource adequacy’ via ‘reliable capacity’ to ensure security of supply. The capacity mechanism proposals are the main focus for new DSR participation. The EWP indicates that Government ‘plans to ensure a fair and equivalent treatment of demand side resources such as storage and demand-side response, alongside generation, with the aim of securing best value investment across the power system’<sup>16</sup>. Options for capacity mechanisms are presently subject to consultation - from a ring-fenced strategic reserve to a number of market-wide alternatives for capacity and reliability markets.

Prior to EWP publication, the ECC Select Committee report on EMR reflected on the complex interplay with other incentive and policy measures, as yet poorly understood. It concluded that : ‘It is important that a capacity mechanism does not close off the potential for innovation in demand-side measures...The EWP must also specify for which demand-side measures the capacity mechanism will be available and clarify whether it is intended to support demand reduction, demand-side flexibility, or both’<sup>17</sup>.

Nonetheless, enabling the demand-side to participate in any new GB capacity market from the outset, signals a positive expectation of a long-term role for DSR in the electricity market. In the meantime there will be a number of challenges:

---

<sup>13</sup> DECC. Energy White Paper. Cm 8099. ‘Planning our electric future: a White Paper for secure, affordable, and low carbon electricity’. 12 July 2011

<sup>14</sup> DECC. Energy White Paper. Cm 8099. July 2011. Paras 42; 1.36 ; 2.1.20.

<sup>15</sup> DECC. Energy White Paper. Cm 8099. July 2011. Paras 6.17, 6.39-42.

<sup>16</sup> DECC. Energy White Paper. Cm 8099. July 2011. Para 20.

<sup>17</sup> ECC Committee. Electricity Market Reform. HC742. May 2011. paragraph 263 & 265.

- In deciding on a preferred capacity mechanism (strategic reserve or market-wide), the demand-side implications need to be well-understood so that DSR is not ‘locked-out’.
- The interaction and boundaries between the Balancing and Capacity Markets will need clarifying to enable the demand-side to find its value in either market.
- Both financial / non-financial hurdles will arise for demand-side delivery in respect of a capacity mechanism.
- Price transparency will be very important in understanding what value is available to DSR providers. This points to initiatives such as auctions / tenders, electronic information platforms and exchanges (local, market-wide), to help establish demand-side value.
- A capacity mechanism may still not be able to incentivise DSR solutions which are not yet cost-competitive with the supply-side (e.g. if high-cost / insufficient value; lacking scale; novel).
- It is not clear how best to incentivise electricity demand reduction – and whether long-term contracts (perhaps equivalent contracts to FIT CfDs) may have a role.
- Load-building - the cost-savings available value to customers between low- and high-priced periods may not prove sufficient incentive on their own to deliver electricity ‘load-building’ at scale.
- Peak-avoidance in the networks - it is not clear how system-wide peak-avoidance secured via capacity-contracts may interact with schemes for peak-avoidance in the networks.
- Pre-2020, continued focus on developing greater demand-side practical experience in System Balancing - and in the Networks via innovation initiatives such as LCNF and via RIIO – remains desirable<sup>18</sup>.

**Our GB Electricity Demand project will inform many of the core electricity demand-side issues and questions raised by the Energy White Paper and by Electricity Market Reform.**

### **Energy Demand Side Policies and Measures – Implications for Electricity Demand Side**

There are many demand-side measures and incentives, many of which interact and impact on electricity demand. However, relatively few impact directly on – or are directed explicitly at -

---

<sup>18</sup> Sustainability First. Response to DECC consultation. Possible Models for a Capacity Mechanism. October 2011.

electricity demand response. Some, but not all, address electricity and / or gas demand reduction.

- **Eco-Design Framework Directive** – far-reaching regulatory measure aimed at reducing electricity (and energy) consumption and growth across all economic sectors. The European Commission estimates that electricity savings potential from Eco-Design measures may amount to 25% of the EU's 2020 20% energy efficiency goal. By end-2012, Eco-Design Regulations will cover ~80% of the product groups responsible for final electricity consumption in the EU<sup>19</sup>.
- **1<sup>st</sup> Phase – Residential and Services (Tertiary) Sectors.** By end 2012, 100% coverage of product groups responsible for electricity consumption in these sectors<sup>20</sup>.
- **2<sup>nd</sup> Phase – Industrial Sector.** Regulations currently cover 60% of electricity consumption in the industrial sector – includes electric motors; pumps, compressors, fans. Preparatory studies include – A/C, ventilation, furnaces & ovens, machine tools, professional refrigerating & freezing equipment, transformers.
- **Certificates – Display Energy Certificates** - for public buildings will extend to large commercial buildings from end-2012. **Energy Performance Certificates** - for home-owners and tenants. From April 2012 will incorporate more targeted information on energy demand reduction savings and Green Deal insulation measure paybacks.

#### **I&C Sectors - CCL & CCAs; CRC Energy Efficiency Mechanism; Green Deal (Commercial).**

- **The Climate Change Levy (CCL)** - came into effect on 1st April 2001 and applies to energy used in the non-domestic sector (industry, commerce, and the public sector). The levy does not apply to fuels used by the domestic or transport sector, or fuels used for the production of other forms of energy (e.g. electricity generation). In order to protect the competitiveness of energy intensive sectors subject to international competition, Climate Change Agreements (CCAs) were introduced alongside the levy. CCAs provide a 65% discount on the levy if targets are agreed and met for improving energy efficiency or reducing greenhouse gas emissions<sup>21</sup>.
- **CRC Energy Efficiency Mechanism** - applies to the service sector, public sector and other less energy-intensive industries – i.e. for organisations not included in the EU ETS. The CRC EEM covers all organisations whose electricity consumption through half hourly meters is greater than 6,000MWh/yr – equivalent to an annual electricity bill of around £500k. All energy other than transport fuels will be covered, such as electricity, gas, fuel and oil. The scheme features an annual league table that ranks participants on energy efficiency performance, as a reputational driver. The scheme encourages

<sup>19</sup> Marie Donnelly. Director. Directorate C. New and renewable sources of energy, energy efficiency and innovation. Slides. 11 November 2010. Green Alliance workshop. London.

<sup>20</sup> Currently, eight Regulations cover 50% of household electricity consumption; 30 % coverage of 'tertiary' sector – street lights, office lights etc.

<sup>21</sup> DECC Climate Change Agreements page: <http://www.decc.gov.uk/en/content/cms/emissions/ccas/ccas.aspx>

organisations to develop energy management strategies that promote a better understanding of energy usage.

## Households and Micro-Business Sectors

- Household Sector - CERT, CESP, Green Deal and ECO** - Obligations on energy retailers to achieve energy savings by household customers. Achieved mainly by subsidising insulation measures designed to address lofts and cavity walls – so in existing homes more likely to support reduced gas-use and affordability than electricity demand reductions. For off gas-grid homes with electric heat, should support electricity demand reduction<sup>22</sup>. Under CERT there have been some electricity-specific measures, e.g. demand reduction via promotion of A-rated appliances and light-bulbs, and, latterly, a demand-response trial of 3,000 Indesit RWEnpower frequency-responsive fridges. **Green Deal** (from 2012) will see Green Deal providers (energy retailers and others) offer to install mainly loft and cavity wall insulation for households with the costs added to the electricity bill and recovered over 25 years. Savings likely to be mostly on the heat-side, and therefore, initially, of gas-demand. **ECO (Energy Company Obligation)** (from 2013) – to run alongside Green Deal with targeted help for low-income / vulnerable customer groups and to provide higher-cost efficiency measures in hard-to-treat homes (e.g. solid walls). Again, likely to support gas-savings initially, but longer-term the hope is to underpin efficient electric heat.
- MicroGeneration Strategy<sup>23</sup> & <5MW Feed-In Tariff** - Supports low-carbon electricity production, demand reduction and export. However, because FIT incentive is paid at a flat, non-time differentiated rate, it effectively supports ‘spill’ onto the Distribution network, regardless of knock-on physical or financial impacts. As currently designed, the structure of the fixed FIT incentive effectively fails to incentivise Demand Response via (1) storage at low-priced periods and / or (2) exports at high-priced periods.
- Renewable Heat Incentive** – Regulations June 2011 – key driver in driving a GB market for renewable heat<sup>24</sup>, including, for example, biomass boilers and electric heat-pumps. Later this decade, policies for renewable heat may lead to electricity demand growth as well as unresolved questions at this point about flexibility at peak.
- Energy labelling, Eco labels etc.** – increase customer energy-efficiency awareness at point of appliance purchase.

<sup>22</sup> ~4.5 million off-gas-grid homes, of which, say, ~ 1 million with Econ 7 - and so already off-peak.

<sup>23</sup> Published June 2011.

<sup>24</sup> UK heat-share of EU Renewable Energy Target ~12% by 2020.

## Electricity Infrastructure – Implications for Electricity Demand Side

**Smart Meters** – ~17% of expected net benefit of national smart meter roll-out relates to expected reduction in electricity demand plus, say, a further 10% of the benefit being attributed to demand response potential and EU ETS allowance savings factored into the GB impact assessment<sup>25</sup>. **Smart Meter Prospectus** - published March 2011. Key measures:

- Data Communications Company / Interoperability by 2014;
- I&C roll-out by 2014 – smarter metering services; SMEs & Households by 2019.

In reality, a great many measures currently being addressed in the Smart Meter Implementation Programme will impact on the eventual GB potential for realising both electricity demand response and for electricity demand reduction, including the arrangements and measures for :

- Data access and consent
- Customer information and feedback
- Meter capability – functional requirements and technical specification (e.g. speed)
- Meter communications (including arrangements for HAN, WAN)
- Possible half-hourly settlement for more customers in the below 100kW market.

## Distribution and Transmission Networks – Innovation Measures

A recent paper by Frontier Economics<sup>26</sup> for the Ofgem / DECC Smart Grids Forum gives a comprehensive overview of GB network issues and longer-term smart grid development. Major distribution network challenges will include two-directional power flows; network stability and control; and active network control and management.

Frontier Economics outline how Ofgem is evolving approaches to network regulation to manage uncertainty through greater innovation. Measures for smarter networks address integrating intermittency and encouraging customers to manage their demand:

- Distribution Price Control Review 5 (DPCR 5 – 2010-15) – and Common Distribution Charging Methodology introduces more cost-reflective network charges by DNOs for suppliers, including initial ToU network charges, to help incentivise deferred capex. Early outcomes likely to feed into DPCR 6 (from 2015).
- Innovation - Low Carbon Networks Fund (LCNF) for electricity distribution networks ; RIIO (Revenue = Incentives + Innovation + Outputs): new eight-year price control, initially for Transmission and gas distribution from 2013 (and from 2015 for Electricity Distribution). Ofgem seeking to incentivise innovation for avoided peak-related capex and improved network control. DPCR 6 will shape network development in 2020's, including measures for active networks.

---

<sup>25</sup> **GB Smart Meter Impact Assessment** – Central Case. August 2011. Estimated Average Customer Electricity Demand Reduction – 2.8%. Estimated Peak Shift – assumed as an economic benefit of £800m. **Ireland** – 8.8% peak-shift and 2.4 % reduction. EDRP – from 7-10 % peak-shift and 2-4% reductions with sustained advice.

<sup>26</sup> How to Deliver Smarter Grids in GB. Frontier Economics. A report prepared for the Smart Grids Forum. April 2011.

- Other innovation incentives include : Innovation Funding Incentive (IFI) (until end DPCR5) ; Network Innovation Competition (NIC) to replace LCNF / RIIO from 2015 ; Technology Strategy Board pilots

### **EU Policy Developments – Implications for Electricity Demand Side.**

From an EU perspective, there is currently quite some momentum to electricity demand-side policy development. This includes:

- Draft Energy Efficiency Directive. (Article 12 discussion).
- Commission Smart Grids Task Force – including draft Commission Communication on Smart Grids;
- CEER (Council of European Energy Regulators) initiatives on regulating smart meter roll-outs – for example : recent CEER consultation on Demand Response and Smart Meters; ACER (Agency for Cooperation of Energy Regulators<sup>27</sup>) consultation on Electricity Balancing Framework Guidelines.
- Formation of a business-led European Smart Energy Demand Coalition<sup>28</sup>.

### **Conclusion – UK and EU Policy Context for GB Electricity Demand Response and Demand Reduction**

There is as yet limited GB policy cohesion either for electricity demand response or for electricity demand reduction between policies and measures on the electricity-supply and electricity demand-sides. Moreover, many GB organisations and companies remain geared to supply-side considerations, and have yet to adopt an integrated or unified approach, even within their own organisations, in considering the electricity demand-side.

DECC's 2050 Pathways Analysis was an initial high-level attempt to enable consideration of the supply and demand-sides in-the-round. Recent initiatives in both DECC and Ofgem make a start in bringing together some thinking and initiatives. For example, the Energy White Paper published in July 2011 indicated that Ofgem would develop an Electricity Systems Framework. Ofgem has also embarked on its Smarter Markets Initiative Strategy Project. DECC is proceeding with new initiatives on, inter al, electricity market reform, its electricity efficiency assessment and an electricity systems policy – alongside the major smart meter implementation programme, which itself has a strong focus on demand-side benefits realisation. The DECC / Ofgem Smart Grids Forum will publish a new scenarios analysis and an initial smart grids economic evaluation framework in 2012.

**Part 1 of this paper has set out at a high-level how GB electricity demand presently sits among the very many energy policy initiatives and measures - both for electricity supply and demand. A key question remains as to how these many initiatives can best integrate to produce practical and cost-efficient outcomes for electricity demand-response and for electricity demand-reduction. This topic will be addressed via Smart Demand Forum papers in Year 2.**

---

<sup>27</sup> Successor agency to ERGEG – European Regulators Group for Electricity and Gas.

<sup>28</sup> [www.smartenergydemand.eu](http://www.smartenergydemand.eu) ; <http://sedc-coalition.eu> ;

## 5. Electricity Demand Side Definitions

### Electricity Demand Side Definitions

It is important to be clear about definitions for terms that are commonly used in the electricity demand side arena. This is for two reasons. Firstly, because, unlike the supply side, where definitions are well established and often written into regulatory and commercial arrangements, this is not the case for the demand side. Secondly, because clear definitions will make it easier to establish what different aspects of the demand side can offer in terms of value to different actors in the electricity value chain and to the electricity system as a whole.

This section of the paper provides working definitions for seven key demand side terms and some further elaboration on what is covered by those terms. These are working definitions that we have developed ourselves although they are based on many definitions in use elsewhere. The key terms defined and explained in this section are:

- demand side
- demand side management
- load management
- demand response
- demand reduction
- energy efficiency
- smart grids

At the end of the paper there is also a glossary containing a number of other definitions that will be relevant in the demand side arena.

### Demand side

The **demand side** consists of the end-users of electricity – households, commercial, industrial and public sectors and the uses they make of electricity – e.g. heat, lighting, motors, equipment, appliances. Increasingly the demand side will also include the ability of these customers and consumers to supply themselves with electricity and to export electricity into the system, via microgeneration and distributed generation.

### Demand side management

**Demand Side Management (DSM):** The planning, implementation, and monitoring of activities designed to encourage consumers to modify patterns of electricity usage, including the timing and level of electricity demand. Demand-Side Management includes **demand response** and **demand reduction**.

Crossley (2004) says that: “The term (DSM) has been used to refer to a wide range of activities, including:

- Actions taken on the customer side of the electricity meter (the ‘demand side’), such as energy efficiency measures and power factor correction;

- Arrangements for reducing loads on request, such as interruptibility contracts, direct load control and demand response;
- Fuel switching, such as changing from electricity to gas for water heating; and
- Distributed generation, such as stand-by generators in office buildings or photovoltaic modules on rooftops.”

DSM may be aimed at tackling problems or achieving cost reductions in networks, system operation or wholesale power supply by:

- Reducing demand peaks, for example when utilisation of power comes close to its limits of availability - and thus maintain short term system reliability
- Shifting loads between times of day or even seasons, to ameliorate and / or avert problems in electricity networks and over the longer term avoid or defer the need for network augmentation;
- Filling demand valleys to better utilise existing power resources

DSM can thus contribute to a number of objectives:

- Improved markets – providing short-term responses to electricity market conditions (**‘demand response’**), particularly by reducing load during periods of high market prices caused by reduced generation or network capacity.
- Reductions in overall electricity demand to produced economic and environmental benefits.
- Shifting between one type of supply to another with more favourable characteristics, for example, in terms of the environment (e.g. as electricity systems are de-carbonised, switching to heat pumps or electric vehicles away from heating and transport sources using fossil fuels)<sup>29</sup>.

## Load management

Also related to **demand side management** is the term **load management**. **Load management** is defined as actions taken to impact upon the amount of electricity demand at any one time i.e. to reduce or increase it, typically through price incentives (tariffs) or direct load control.

## Demand response

**Demand response (sometimes called demand side response)** - changes in electricity usage by end-use customers from their normal consumption patterns, in response to changes in the price of electricity, or to incentive payments. Designed (1) to induce lower electricity use at peak periods or to encourage use in off-peak periods and / or (2) to provide flexibility at any time of the day in support of cost-efficient balancing of the electricity system overall. (In the future, for example, demand response could aim to increase customer use at periods of high wind output and to decrease customer use at periods of low wind output). Both (1) lower use at peak periods and (2) general demand-side flexibility may help reduce wholesale costs

---

<sup>29</sup> Above lists based on Crossley, 2004; IEA DSM programme home page.

(short and long run), and / or reduce network reinforcement costs, and support overall electricity system reliability.

The key feature of demand response that distinguishes it from the broader term “demand side management” therefore, is the almost exclusive emphasis on **shifting demand**. Shifting demand between times of day may lead to overall reductions in electricity use but may leave overall demand unchanged or even lead to an increase in overall demand. Peak demand for **network distributed electricity** may also be reduced by the customer switching instead to using **on-site generation**.

Many of the definitions of demand response tend to focus almost exclusively on its role in the wholesale market and system operation side and ignore network issues. For example:

**Demand response** refers to “changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.” (US Department of Energy (DOE), National Action Plan for Energy Efficiency 2006)

**Demand response** mechanisms manage customer consumption in response to supply conditions, for example by inducing end-users to consume less electricity at times of high wholesale market prices or when system reliability is jeopardised. (European Commission Communication on Smart Grids, 2010)

**Demand response:** ‘Changes in electric usage by end-use customers / micro-generators from their current / normal consumption / injection patterns in response to changes in the price of electricity over time, or to incentivise payments designed to adjust electricity usage at times of high wholesale market prices or when system reliability is jeopardised, This change in electric usage can impact the spot market prices directly as well as over time’. (Council of European Energy Regulators (CEER),<sup>30</sup> 2011)

However, in its work on demand response, Ofgem did note the potential impacts in the three aspects of the electricity system as illustrated below.<sup>31</sup>

Impacts noted by Ofgem of DSR on different parts of the electricity value chain:

- Potential wholesale cost savings: Short Run Marginal Cost Saving (SRMC): the difference between the SRMC of the peak generation plant displaced by DSR and the lower replacement cost of off-peak generation plant; and capital cost savings: the

---

<sup>30</sup> Council of European Energy Regulators (CEER), 2011 Draft Advice on the take-off of a demand response electricity market with smart meters. Public Consultation Paper - C11-RMF-31-03. 04 May 2011 p.7/32 of the CEER.

<sup>31</sup> Ofgem. Demand Side Response : a discussion paper, July 2010, p.19,26 and 31

potential capital cost savings associated with DSR being able to displace the need to invest in new generation plants to meet peak demand<sup>32</sup>.

- Potential network cost savings: The use of DSR as an alternative to peaking plant generation may reduce the need for load-related investment in the electricity distribution network in the long-run in some regions. Network operators will however need assurance that DSR at peak periods is reliable. Ofgem calculate possible DSR savings in terms of avoided **load-related** capital expenditure<sup>33</sup>. Ofgem also expect that DSR may displace capital expenditure for connections of generating plant, and that related capex savings could be available. However, as a non-regulated activity, treatment of potential savings from avoided generation connections required more work than possible for Ofgem's initial high-level calculations. Ofgem noted that there may also be some investment savings arising from the transmission network.
- System balancing - there may be benefits associated with operating the system more efficiently (since congestion would be reduced) and improving the use of existing generation and network capacity.

Demand response is typically achieved in three main ways:

- Customers can forego or reduce some uses of electricity. For example, raising (air conditioning) or lowering (heating/water heating) thermostat settings, reducing the run time of air conditioners, dimming or reducing lighting levels, are responses that may tend to lead to an overall reduction in electricity use.
- Customers can **shift** electricity consumption to an off-peak time period. For example, a factory might reschedule or defer some production to an overnight shift. Commercial or residential customers could pre-cool their premises and shift load from a higher to lower cost time period. Residential and commercial customers could also choose to delay running certain appliances (notably washing machines, dishwashers, tumble dryers, electric heaters and refrigerator defrost cycles) until prices are lower.
- Customers can **self-generate** electricity using onsite generation, thus reducing their usage of network-delivered electricity<sup>34</sup>.

---

<sup>32</sup> Ofgem DSR modelling was necessarily initial and high-level. In practice, a number of more detailed, additional considerations may arise. Two examples : where the avoided-costs achieved by DSR are the short-run marginal costs of energy, how to account for the long-run costs of any peaking plant still required (ie how to recoup capital costs over fewer hours running-time if DSR displaces plant) ; shifting demand to other periods, may create new demand and new short-run energy costs at other periods.

<sup>33</sup> Not mentioned in the Ofgem paper, but DSR may also *defer* the need for investment, which may also be valuable. Also, Ofgem do not foresee DSR-related cost-savings in the networks in terms of other regulated activity eg in terms of demand connections, diversions and fault-related spend.

<sup>34</sup> Based on Goldman et al. National Action Plan for Energy Efficiency. *Coordination of Energy Efficiency and Demand Response*, 2010. Prepared by Charles Goldman (Lawrence Berkeley National Laboratory), Michael Reid (E Source), Roger Levy, and Alison Silverstein. ([www.epa.gov/eeactionplan](http://www.epa.gov/eeactionplan)),

The methods to facilitate DSR can be broadly classified into three types of products:

- Different types of tariffs. These include time of use (TOU) tariffs, critical peak pricing (CPP) and real-time or dynamic pricing;
- Contracts, typically for I&C consumers, to curtail load (at pre-agreed times or in response to changing conditions on the electricity network); and
- Automated devices including 'smart' controls, thermostats and appliances which respond to either changing conditions on the electricity network or a price signal<sup>35</sup>.

### **Demand reduction**

**Demand reduction** - an actual reduction in the overall electricity used, not just a shifting from peak periods. Other terms used include overall load reduction or overall electricity saving.

As the previous section outlined, **demand reduction** may be achieved through some **demand response** initiatives, but not necessarily as it may result in demand being shifted to off-peak periods (or the customer may self-generate electricity) so that the same amount of electricity is consumed. Demand reduction may also be achieved through **energy efficiency** measures.

### **Energy Efficiency**

**Energy efficiency:** two main definitions: (1) Using less energy (kWh) to achieve the same benefits (e.g. internal temperature, industrial output etc.), (2) Using the same or a lesser amount of energy (kWh) but achieving more benefits (e.g. a warmer home, higher output).

There are in practice many definitions for energy efficiency depending upon the context in which the definition is being used. Some definitions focus on the outcomes (as above) whereas other focus on the activities (measures). A couple of examples are given below.

**Energy efficiency** refers to permanent changes to electricity usage through installation of or replacement with more efficient end-use devices or more effective operation of existing devices that reduce the quantity of energy needed to perform a desired function or service<sup>36</sup>. Change can therefore be achieved through new equipment or behaviour change.

---

<sup>35</sup> Ofgem. op cit p. 10

<sup>36</sup> National Action Plan for Energy Efficiency. *Coordination of Energy Efficiency and Demand Response.*, 2010. Prepared by Charles Goldman (Lawrence Berkeley National Laboratory), Michael Reid (E Source), Roger Levy, and Alison Silverstein. ([www.epa.gov/eeactionplan](http://www.epa.gov/eeactionplan)),

## Smart Grids

**Smart grids.** A smart grid is part of an electricity power system which can intelligently integrate the actions of all users connected to it - generators, consumers and those that do both - in order to efficiently deliver sustainable, economic and secure electricity supplies.

The above definition seems to be developing relatively widespread usage in Europe. It is the definition used in the Smart Grid Routemap developed by the ENSG.<sup>37</sup> On this basis, Frontier Economics also used this definition in their April 2011 paper for the DECC / Ofgem Smart Grids Forum<sup>38</sup> (Almost identical wording is used in the European Technology Platform SmartGrids).<sup>39</sup>

Expanding on the definition, DECC<sup>40</sup> identified that a smart grid is likely to have the following characteristics:

- **Observable:** the ability to view a wide range of operational indicators in real-time, including where losses are occurring, the condition of equipment, and other technical information.
- **Controllable:** the ability to manage and optimise the power system to a far greater extent than today. This can include adjusting some demand for electricity according to the supply available.
- **Automated:** the ability of the network to make certain automatic demand response decisions. It will also respond to the consequences of power fluctuations or outages by, for example, being able to reconfigure itself.
- **Fully integrated:** integration and compatibility with existing systems and with other new devices such as smart consumer appliances.

**As this project progresses, we aim to support development of a clear set of widely agreed GB demand-side definitions.**

---

<sup>37</sup> ENSG (2010) *A Smart Grid Routemap*

<sup>38</sup> Frontier Economics. How to deliver smarter grids in GB. A report prepared for the Smart Grids Forum, April 2011.

<sup>39</sup> The European Technology Platform SmartGrids defines smart grids as “electricity networks that can intelligently integrate the behaviour and actions of all users connected to it - generators, consumers and those that do both – in order to efficiently deliver sustainable, economic and secure electricity supplies.”

<sup>40</sup> (DECC (2009) *Smarter Grids: the opportunity*)

## Part 2 - Baseline Data for GB Electricity Demand 2010

The aim of Part 2 is to:

- Provide a resource on GB electricity use today.
- Improve on present understanding of how electricity is used.
- Establish a well-informed base-line for the GB Electricity Demand project – from which it will build in looking forward to the 2020's.
- Identify important knowledge gaps or missing data regarding particular aspects of GB electricity demand today – e.g. its key uses and characteristics, its current value to different market actors, its potential to be despatched or to be flexible at different times.
- Paint a high level overview of the role that the electricity demand-side plays in the electricity market today – both to inform the project going forward - and also to inform the forthcoming Ofgem Electricity Systems Framework and the DECC Electricity Systems Policy.

1. **Overview**
2. **UK electricity end-use by key economic sector**
3. **GB demand and the electricity system**
4. **Transmission / Distribution interface – distributed generation**
5. **Customer Expectation - system security and reliability**
6. **Variability of demand**
7. **How load is met – the need for flexibility**
8. **Demand-side flexibility**
9. **GB load management 2010**
10. **GB despatchable and deferrable load**
11. **Valuing system flexibility and avoided peak-load**
13. **What is assumed today about flexible GB demand in 2020?**

### Glossary

### Data Annexes

- Annex 1 - Regional consumption data**
- Annex 2 - Estimated electricity end-use by economic sector**
- Annex 3 - Historic trends in electricity consumption**
- Annex 4 - Heat and non-heat uses of electricity - and of other fuels**
- Annex 5 - UK electricity capacity and supply by fuel**

## 1. Overview

The following sections set out the current position in respect of GB electricity consumption (in total, by sector and by usage type) in so far as data is available - and the present role played by the demand side in the GB electricity market. We are taking 2010 as the baseline. However, where the most up-to-date available data stems from earlier years (2008 and 2009), we have made this clear. Some data relates to UK and some to GB – we have made this clear. A Data Annex to this paper sets out more detailed data on GB electricity demand, including on historic trends.

In 2010 in UK, electricity supplied to end-users was 328 TWh, slightly up on 2009 (322 TWh) due to an exceptionally cold December and a slight economic upturn<sup>41</sup>.

<b>GB Generation Capacity and Electricity Demand in 2010</b>	
<b>Generation capacity</b>	<b>~80GW<sup>42</sup></b>
<b>Maximum winter peak demand</b>	<b>~58 GW<sup>43</sup>.</b>
<b>Typical system winter peak</b>	<b>~52 GW<sup>44</sup>.</b>
<b>Minimum summer demand</b>	<b>~19GW<sup>45</sup>.</b>
<b>Typical system summer minimum demand</b>	<b>~22.6 GW<sup>46</sup>.</b>
For almost 80% of the time in 2010, GB electricity demand was at least half of the maximum winter peak level or above i.e. over 29 GW but below the 58GW winter peak.	

**Table 1 GB Generation Capacity and Electricity Demand in 2010**

**Pre-2020** : CCC, DECC and National Grid each anticipate that levels of both peak and overall electricity demand will stay broadly much as now until 2020, due to efficiency measures, improved electricity intensities, and the outlook for economic growth<sup>47</sup>.

**Post-2020**: the assumption is that overall electricity demand will grow as electricity decarbonises, in particular due to electric vehicles and heat. Peak-demand is also expected to grow, depending on the capacity for thermal storage of electric heat. The CCC indicates that electricity demand could rise from current annual levels of around 330 TWh to 450 TWh in 2030 (medium scenario) and 500 TWh by 2050<sup>48</sup>.

<sup>41</sup> DECC. DUKES. 2011. Electricity. Table 5.1. p. 136

<sup>42</sup> National Grid. Seven Year Statement. May 2011. (NG SYS 2011). Operational registered plant.

<sup>43</sup> NG SYS 2011. ~58 GW - 7 December 2010. 17.30h - ACS average-cold-spell peak (i.e. weather-corrected) and unrestricted – i.e. without load management).

<sup>44</sup> NG SYS 2011. ~52 GW - 17 November 2010 - and average demand for that day of 41GW.

<sup>45</sup> NG SYS 2011. ~19 GW - 18 July 2010 – 05.30h.

<sup>46</sup> NG SYS 2011. 22.6 GW - 10 June 2010 - and average demand for that day of 33GW.

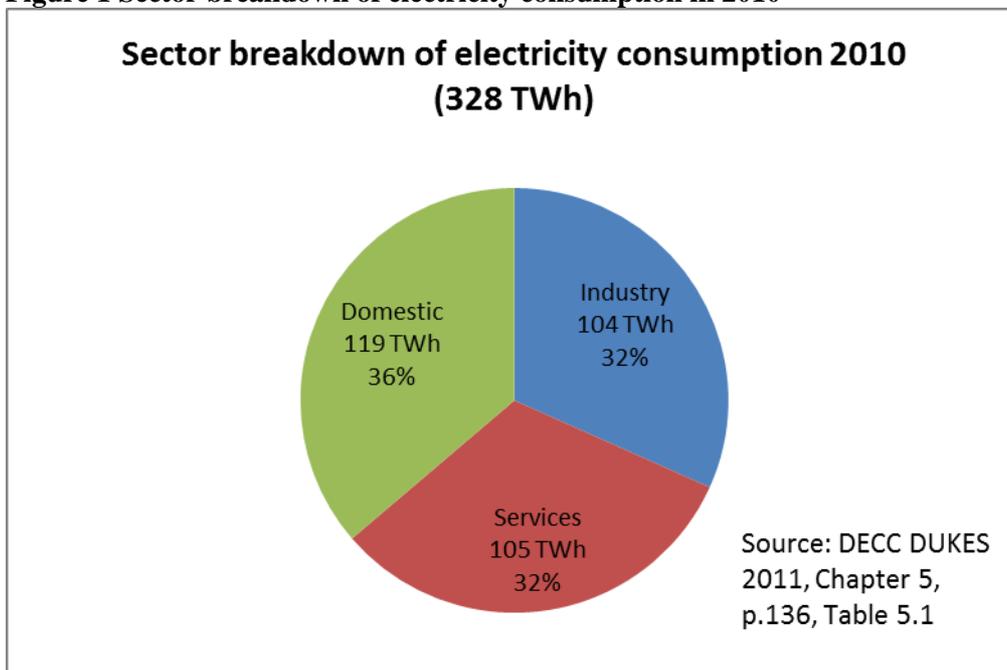
<sup>47</sup> CCC – The Fourth Carbon Budget. P.274. December 2010 ; DECC – Updated Energy and Emissions Projections. URN 11D / 871. Central Scenario. Annex C. Final Electricity Demand. October 2011 ; National Grid – Operating the Electricity Transmission Networks in 2020. Update. June 2011. Para 2.11 & 5.2 – 5.4.

<sup>48</sup> CCC – The Fourth Carbon Budget. p.28 & p.274. December 2010

## 2. UK Electricity End-Use by Economic Sector 2010

In 2010, final UK electricity consumption was 328 TWh. Figure 1 below breaks this down by key economic sector<sup>49, 50</sup>.

**Figure 1 Sector breakdown of electricity consumption in 2010<sup>51</sup>**



At 328 TWh, outturn for UK electricity demand in 2010 was 1 % higher than 2009 (322 TWh). National Grid anticipates a permanent loss of electricity demand of 2.5 GW from the 2008-09 recession<sup>52</sup>. This may be assumed to be mostly across the heavy industry sector – and less so in other industry and the commercial sector. Correlation of electricity demand in the household sector to the economic downturn is less clear.

<sup>49</sup> Excluding energy industry use and losses.

<sup>50</sup> DECC – DUKES. July 2011. Table 5.2. Electricity.

Also – DECC - DUKES 2011. Electricity Chapter 5 – p.119. see p 132 Table 5.3 for a more detailed breakdown of industrial and commercial use

<sup>51</sup> Excluding energy industry use and losses.

<sup>52</sup> National Grid. Operating the Electricity Transmission Networks in 2020. June 2011. P.8. para 2.11

## Breakdown of Electricity Consumption by Economic Sector 2010.

Figure 2 UK Final electricity consumption for industry in 2010 <sup>53</sup>

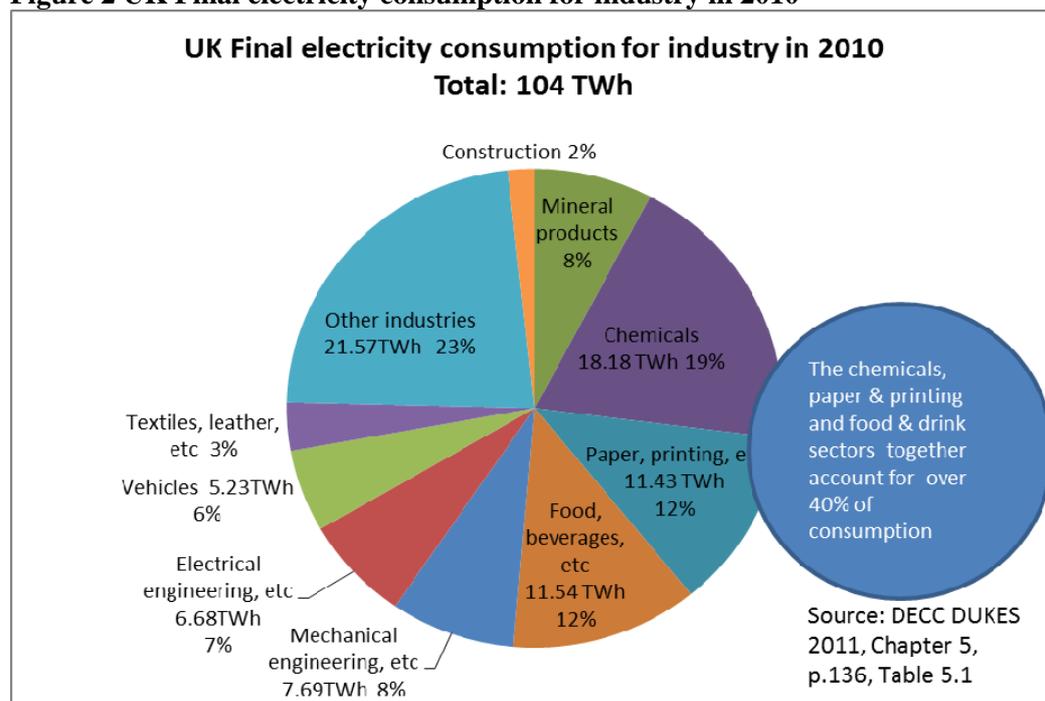


Figure 2 shows the break-down of electricity-use by UK Industry in 2010<sup>54</sup>. Overall industry demand increased in 2010 by 3.6% over 2009. While the 2008-09 downturn impacted on certain industrial sectors (e.g. Iron and Steel), the efficiency improvements in EU ETS industries, and the effect of CCL/CCAs continued to target cost-effective electricity demand-reduction in the highest consuming industry sectors.

<sup>53</sup> DECC. DUKES. July 2011 – table 5.2 p 138 gives TWh Industrial consumption by : Iron&Steel ; Non-Ferrous Metals ; Mineral products ; chemicals ; mechanical engineering etc. ; electrical engineering etc. ; vehicles ; Food, beverages ; textiles, leather ; paper, printing etc.; other industries ; construction. – but NB - not blast-furnaces and ovens – which are included under ‘energy industry use’.

<sup>54</sup> Data based on Standard Industry Classifications, used for Eurostat.

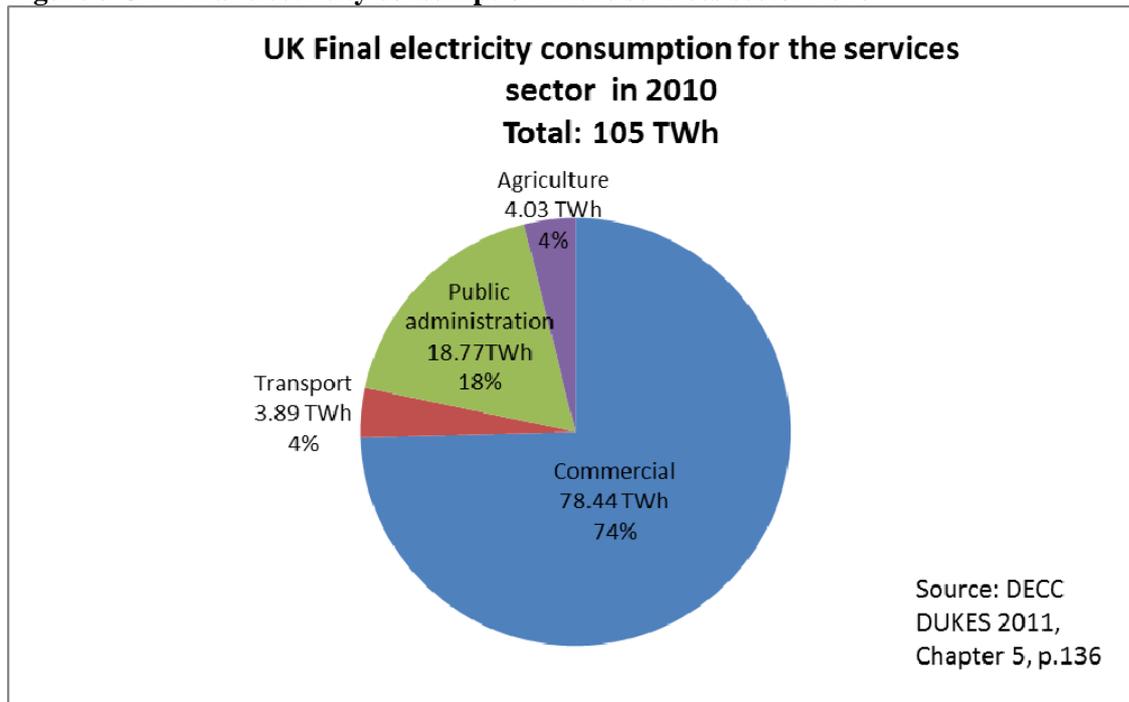
**Figure 3 UK Final electricity consumption in the services sector 2010**

Figure 3 shows Services sector consumption for 2010. Demand remained static overall in 2010 and 2009, perhaps reflecting poor economic conditions plus increased efficiency. Within the services sector, commercial consumption rose by 3% in 2010 from the 5-year low of 2009; agriculture consumption rose by 6% - and public sector consumption fell by 3.4% against the previous record low of 2009<sup>55</sup>.

Going forwards, a common assumption seems to be for most expected growth in electricity demand to be in the commercial sector e.g. presumably from appliance growth in commercial buildings (e.g. electric heat, air-conditioning, ventilation; data centres; commercial refrigeration; and lighting etc.). A better understanding is needed on likely trends in electricity demand growth within different parts of the services sector. To some extent, incentives available under the Carbon Reduction Commitment and Energy Efficiency Scheme, may offset some growth.

<sup>55</sup> DECC. DUKES. 2011. Para 5.9. p.119

## Domestic Sector

In 2010, domestic electricity consumption in the UK was 119 TWh. Table 2 below breaks this down by standard and off-peak (Economy 7) units supplied.

<b>UK Domestic Electricity. Standard and off-peak units supplied to households. 2010<sup>56</sup></b>	
Standard domestic units supplied	79.6 TWh
Standard domestic pre-pay units supplied	13.4 TWh
<b>Total standard units supplied to households</b>	<b>93 TWh</b>
Economy 7 and other off-peak domestic units supplied	21 TWh
Economy 7 pre-pay domestic units supplied	4.5 TWh
<b>Total off-peak domestic units supplied to households</b>	<b>25.5 TWh</b>
<b>Total domestic units supplied to households</b>	<b>118.6 TWh</b>
<b>Total off-peak units as a percentage of all domestic units supplied – 21 %</b>	

**Table 2 UK Domestic Electricity. Standard and off-peak units supplied. 2010**

Around one-fifth of domestic electricity supplied in the UK in 2010 was therefore off-peak. This is down from around 30 % 2007. It is fair to assume that this off-peak electricity is mainly for heating (probably storage heaters) and for some hot-water heating, much in off-gas-grid areas. Up-to-date and reliable figures for the total number of domestic customers on off-peak tariffs are not readily available. An estimate of some 1.5 to 2 million customers in GB still on off-peak tariffs may be reasonable<sup>57</sup>.

From January 2011, the Ofgem benchmark figure for typical household electricity consumption is 3,300kWh pa (median)<sup>58</sup> – unchanged from a 2003 base-line<sup>59</sup>. For off-peak electricity consumption (e.g. Economy 7) – most likely for electric heating and possibly electric hot-water heating, much in off-gas grid areas – the typical consumption figure (median) adopted as a benchmark by Ofgem is 5,000 kWh pa – down from 6,600 kWh<sup>60</sup> in 2003.

<sup>56</sup> DUKES. 2010. DECC. July 2011. p.139. Table 5.3. July 2011. Commodity balances – Public distribution system and other generators.

<sup>57</sup> English Housing Survey 2008. DCLG. Housing Stock Report. Pp 117-119 & e-mail exchange with Vicki White. Centre for Sustainable Energy (CSE). Bristol. The EHS housing stock model / sampling suggests: **1.5 million dwellings total in England** have off-peak electric heating. 1.436 m - 7-hour offpeak - plus 77,000 - 10-hour offpeak. Some estimate would need to be added for Wales and Scotland.

<sup>58</sup> Ofgem. Factsheet 96. Typical domestic energy consumption figures. 18 January 2011. Range - Typical low consumption value : 2,100kWh ; Typical high consumption value : 5,100kWh

<sup>59</sup> A mean consumption figure – and not median consumption - was used as the 2003 baseline.

<sup>60</sup> Mean figure

Table 3 below is an estimate of UK household electrical appliance load, which draws from DEFRA’s Market Transformation Programme Stock Model. It excludes electric heating and hot water – estimated at around 28 % of UK domestic electrical load.

<b>Estimated UK Domestic Electrical Appliance End-Use 2009 (minus heating and hot water)<sup>61</sup></b>		
<b>Domestic Electrical Appliance Use</b> (estimates from MTP Ownership Stock Model based)	<b>% of domestic electrical appliance load 2009</b> (estimated)	<b>TWh pa in 2009</b> (estimated)
<b>Domestic Wet Appliances</b>	17%	14.2
<b>Cold Appliances</b>	17%	14.4
<b>Cooking of which</b> Electric ovens - 3.8 TWh Electric hobs - 3.2 TWh Microwaves - 2.4 TWh	11%	9.4
<b>Kettles</b>	5%	4.2
<b>All Consumer Electronics</b> <i>Includes</i> TVs - 8.3 TWh Power Supply Units - 3.6 TWh Videos DVDs - 3.1 TWh Games Consoles - 0.6 TWh	24%	20.8
<b>Lighting</b>	19%	15.8
<b>PCs / Domestic ICT</b> <i>Includes</i> PCs - 3.9 TWh Laptops - 0.7 TWh Monitors - 1.5 TWh Imaging - 0.4 TWh	7%	6.5
<b>TOTAL</b> – Estimated UK domestic Electrical Appliance End-Use - <b>Minus heating and hot water 2009</b>	100%	85.3 TWh per annum
Domestic heating and hot water electricity consumption 2009 - estimated at 32.8 TWh <sup>62</sup> .		

**Table 3 Estimated UK Domestic Electrical Appliance End-Use 2009 (minus heating and hot water)**

Improvements in appliance efficiency for white goods and lighting, are to some extent off-set by: more and smaller households; higher disposable incomes (pre-2009); more individual appliance ownership; more types of appliance; (including, small domestic appliances, IT and consumer electronics); and, increased availability of lighting, appliances and electronic goods in homes. The trend to more households (up 16% since 1990) and to smaller households contributes to increased electricity consumption per head, against generally downward overall energy consumption per household<sup>63</sup>.

<sup>61</sup> Owen G & Ward J ‘Smart Tariffs and Household Demand Response for Great Britain’. Sustainability First. March 2010 p.82

<sup>62</sup> 25.5 TWh offpeak units supplied for domestic use in 2010. DUKES. P.139. Table 5.3. July 2011.

<sup>63</sup> Owen G & Ward J. ‘Smart Tariffs and Household Demand Response for Great Britain’. Sustainability First. March 2010. p.55

Detailed half-hourly electricity demand-profiles are increasingly available from smart meter research (e.g. EDRP, LCNF). Disaggregated household profiles will greatly help to improve on our current knowledge of which appliances households use, how they use them, and at what times of the day. This in turn will help to provide a more realistic understanding than now of what domestic electrical load could potentially reduce altogether - or shift - to a different time of day.

**Volumes of Electricity Demand by Economic Sector – GB Meter Points**

Exelon<sup>64</sup> indicates that around two-thirds of all GB electricity consumption can be attributed to just 2.3 million electricity meter points – i.e. to just 8% of all electricity meters (in practice, to some 2 million customers - out of a GB likely total of ~29 million).

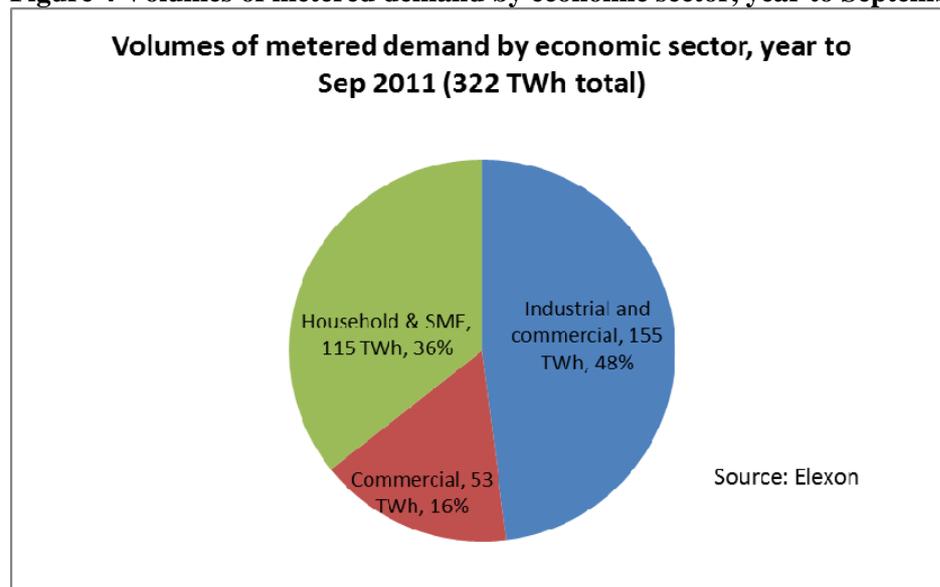
Table 4 below shows GB annual metered energy for half-hourly and non-half hourly consumption by load-profile class. Load Profiles 1 and 2 are domestic customers – i.e. household and micro-businesses. All other Load Profiles are Commercial, with Profiles 5 and 8 being the largest individual customers.

<b>GB Half-Hourly and Non-Half Hourly Annual Energy Consumption Recorded (TWh) at September 2011</b>		
<b>Load Profile Class</b>	<b>MSIDs<sup>65</sup></b>	<b>Annual Energy (TWh)</b>
<b>Domestic Customers</b>		
<b>LP 1 – Domestic Unrestricted</b>	22,240,503	<b>86.1</b>
<b>LP 2 – Domestic Economy 7</b>	<b>5,053,598</b>	<b>29.1</b> Estimated broad split: 35% night load; 65% day load.
<b>Commercial Customers</b>		
<b>LP 3 – Non-Domestic Unrestricted</b>	<b>1,619,082</b>	<b>23.4</b>
<b>LP 4 - Non-Domestic Economy 7</b>	<b>505,393</b>	<b>11.9</b> Estimated broad split : 26% night load; 74 % day load.
<b>LP 5 – Non-Domestic Maximum Demand (MD) Customers with a Peak Load Factor (LF) of &lt;20%</b>	<b>37,084</b>	<b>2.7</b>
<b>LP 6 - Non Domestic MD Customers w Peak LF 20-30%</b>	<b>54,238</b>	<b>5.4</b>
<b>LP 7 - Non Domestic MD Customers w Peak LF betw 30-40%</b>	<b>25,560</b>	<b>3.1</b>
<b>LP 8 - Non Domestic MD Customers w Peak LF over 40%</b>	<b>49,779</b>	<b>6.3</b>
<b>Total – Non-Half Hourly Metered</b>	<b>29,585,237</b>	<b>168</b>
<b>Half-Hourly Metered</b>	<b>~117,000</b>	<b>155</b>
<b>Total Annual Metered Energy (TWh) – Half Hourly and Non-Half Hourly Metered</b>	<b>29, 702, 237</b>	<b>322 TWh total annual</b>

**Table 4 GB Half-Hourly and Non-Half Hourly Annual Energy Consumption Recorded (TWh) at September 2011**

<sup>64</sup> Exelon. Smarter Settlement. Making the Most of Tariff Innovation. March 2011 - plus email communication. September & October 2011.

<sup>65</sup> Metering System Identifiers (MSID)

**Figure 4 Volumes of metered demand by economic sector, year to September 2011**

Given an annual GB electricity consumption of 322 TWh<sup>66</sup>, Figure 5 shows that for the year September 2011:

- **Industrial and Commercial Half-Hourly Meters – 155 TWh consumption via 117,000 half-hourly meters.** i.e. ~just under 50% of total annual GB electricity consumption.
- **Commercial (Load Profiles 3-8) – 52 TWh consumption from ~2.2 million meters** (most not half-hourly nor half-hourly settled – but smarter metering to be installed by 2014 for Load Profiles 5-8) - ~ 16% of annual GB electricity consumption.
- **Household & SME Consumption – 115 TWh via 27 million meters** – i.e. 36% of GB electricity consumption. Of this consumption, ~20% is recorded in DUKES as Economy 7 units (25.5 TWh)<sup>67</sup> – amounting to ~8% of all GB electricity supplied. Electricity consumed by households on an ‘unrestricted hours’ basis amounts to 26% (86TWh) of all electricity use.

Typically, distribution networks are designed to deal with an average household maximum demand after diversity of 1.5 kW, but in practice there are a range of estimates for average individual household demand at peak<sup>68</sup>. Nor do these individual

<sup>66</sup> i.e. not Northern Ireland.

<sup>67</sup> 25.5 TWh offpeak units supplied for domestic use in 2010. DUKES. P.139. Table 5.3. July 2011.

<sup>68</sup> Individual household demand varies widely depending on appliance ownership, usage etc. A typical kettle is 2-3 kW. A typical power shower may be ~ 10 kW. Household and service cables are designed to take a considerably higher load. (Service fuses are rated at an equivalent of 60 amps - or 100 amps in modern properties - i.e. a maximum load of ~15 kW or ~20 kW respectively). In practice, an individual cable-feeder from a substation transformer may connect between 50-100 properties – but ‘diversity’ or statistical averaging is assumed - to avoid over-engineering the network. Typically, distribution networks are

peak demand estimates necessarily offer a good guide system-wide, to likely total household consumption at daily peak. The Ofgem DSR paper (July 2010) assumed that around half of total demand from households was at peak, continuing in a long ‘tail’ into the evening.

**The insight that two-thirds of GB electricity is consumed by fewer than 10% of all GB customers raises some key questions as to how far it may – or may not - make initial sense to target measures at GB’s 2.3 million I&C customers – either to reduce electricity-use – or to shift load — rather than at the 27 million SME and household customers. Not least, it will be important to understand more about the potential price-elasticity and flexibility of different types of customer, their different loads and their different requirements at particular times of the day or year.**

**Later papers for this project will explore these and related questions, including what comprises peak-load, the likely extent of flexible and or despatchable load across economic sectors, both today and in the future, and consider in which sectors new price-responsive or flexible load (e.g. electric vehicle load) is most likely to grow.**

---

designed to deal with an average demand ‘after diversity’ of 1.5 kW (which includes a safety margin).  
Source : e-mail communication with a distribution network – October 2011.

National Grid estimate maximum household demand after diversity in 2010 – range 1.5 -3 kW (range 5-24 kWh/ day per household). Presentation to Low Carbon London (LCL) Learning Workshop – 17 October 2011.

IHS Global Insight. Demand Side Participation Report for DECC. July 2009. P.37 – states : The average residential demand across all 26 million residential customers is around 0.8kW to 1kW at peak times but this hides a wide degree of diversity.

### 3. GB Demand and the Electricity System.

In their recent report for the Electricity Networks Association, KEMA summarise the main characteristics of the present power system as follows<sup>69</sup> :

- **Two-way power flows on the Transmission Network** – bulk power flows which can change direction depending on which generation is operating. The system has been designed with this capability.
- **One-way power flow on the Distribution Networks** – uni-directional electricity flow, fed from grid supply points on the transmission system and delivering energy to customers. Reverse flows (e.g. from Distributed Generation) are problematic, due to inadequate control and lack of fault detection systems.
- **Remote generation** – large power plants located away from demand centres.
- **Limited communication and automation capability** – act as a limitation, especially at the Distribution level, to monitor power flows, voltages and to respond to faults.
- **Passive grid** – with limited communication and automation equipment, the distribution networks are designed to connect maximum-demands on a ‘fit and forget’ basis to satisfy peak demand in a passive manner, with limited need for direct interaction to facilitate peak-management.
- **Passive customers** – consumers are connected ‘passively’ to the system – not actively.

Today, the connection, system security and operational requirements and information flows among major industry actors – including the system operator, the transmission and distribution networks, generators, suppliers, and a handful of very large customers who are directly connected to the transmission network - are governed by a series of inter-linked statutory codes and agreements, enforced via the Electricity Licence regime.

Distributed generators and large customers connected beneath the level of the Grid Supply Point have governance arrangements for connection and for operation of their plant and equipment, more appropriate to their size.

Over time, with the connection of more distributed generators, including more micro-generation, and with the development of more active demand, there will be a need to revise and develop some aspects of the current governance frameworks to facilitate management of more complex power flows over the networks. This is likely to include certain aspects of the inter-face with distributed generators and micro-generators / active customers (with or without a de-minimis threshold), to enable more active distribution networks to evolve in a stable, secure and cost-efficient way.

---

<sup>69</sup> GB Demand Response. Report 1. KEMA. March 2011. Report for the Electricity Networks Association. p.9

#### 4. Transmission / Distribution Interface – distributed generation

**CHP-generated electricity:** In 2010, CHP generated 26 TWh of electricity, 7% of total electricity generated in the UK that year.

In the commercial and industrial sectors electrical outputs from CHP accounted for approximately 14 % of electricity consumption<sup>70</sup>.

**Transmission-connected capacity:** There is 2.2 GW of transmission-connected CHP from large CHP plant (2011)<sup>71</sup>.

##### **Distributed generation today:**

In 2011 there is 8.96 GW installed capacity from distributed small and medium generators<sup>72</sup>. This includes:

- 0.88 GW of distributed CHP (10% of total embedded capacity).
- 2.85 GW distributed wind capacity (onshore & offshore - 33% of total embedded capacity).
- 664 MW biofuels distributed capacity.
- 435 MW distributed hydro capacity.

##### **Micro-generation**

In late September 2011, the Ofgem Register showed almost 300 MW of micro-generation capacity installed since introduction of the <5MW Feed-In Tariff in April 2010. Of this, installed Photovoltaic (PV) capacity was approaching 250 MW : of which, around 200 MW was household (some 73,000 household installations). Future microgen growth, in particular for PV, will depend significantly on future paybacks available via the FIT for household and non-household projects.

##### **Improvements in knowledge of distributed generation**

The system operator – plus the transmission and distribution networks - will increasingly desire information about the connection of embedded generation and its output, both for reasons of system security and stability and also to allow cost-effective management of network assets and of the electricity system overall.

For example, National Grid<sup>73</sup> indicate a need to understand the level of embedded generation at Grid Supply Points (GSP) when forecasting demand at a national level – because, distributed generators reduce demand at the GSP. They wish to understand demand at the GSP (net of generation) to better inform (1) supergrid transformer outages and (2) to

<sup>70</sup> DECC – DUKES. 2011. Chapter 6: CHP. Assuming 104 GWh final consumption for industry and 78 GWh for commercial consumption, then CHP accounts for 14% of electricity. Taking a wider ‘Services’ definition, which includes transport and public administration, then CHP accounts for 12% of electricity.

<sup>71</sup> 2011 National Electricity Transmission System (NETS) Seven Year Statement

<sup>72</sup> 2011 National Electricity Transmission System (NETS) Seven Year Statement. Note not all the embedded plant of less than 1 MW located in England Wales is included (chapter 4, page 3).

<sup>73</sup> National Grid. Operating the Electricity Transmission Networks in 2020 (Update). June 2011.

anticipate future transmission investment needs and / or *locational* contracts for Short Term Operating Reserve (STOR) – see section 9 below.

Industry regulations require distributed generators – including small micro-generators – to notify the distribution networks of their connections. Nevertheless, the Distribution Networks need to improve their knowledge of distributed generators wishing to connect to their networks, including micro-generators, due to their potential to impact on, for example, network stability, voltage control, constraint management and network reinforcement.

**Demand-side impacts of distributed generation, including the key commercial, regulatory and customer issues, including for both transmission and distribution, will be a future area of interest for this Project.**

## 5. Customer Expectation – system security and reliability<sup>74</sup>

GB electricity customers expect and enjoy high standards of (1) power system security (energy) and (2) network reliability. Most customers, with the possible exception of a relatively few rural customers, have a justifiably high expectation of a very secure and high-quality electricity supply at all times.

Moreover, across all economic sectors, very few of the GB's 29 million electricity customers have much expectation that they might (or could) adapt their consumption - either to match available supplies - or to respond to underlying system costs. Only the largest industrial customers - and customers on Economy 7 - presently do so<sup>75</sup>.

### Electricity Network Reliability

The electricity networks are planned, built and operated to a number of security standards (for example, the Grid Code and Security and Quality Supply Standards for Transmission; the Distribution Code and Connection Agreements for Distribution<sup>76</sup>). These arrangements have statutory status and are enforced through the Licence regime.

**Transmission** – The TOs have regulatory incentives and statutory obligations to create an operating environment designed to minimise energy unsupplied, and have a very strong record. In 2008-09 National Grid reported an annual loss of 335 MWh – equal to a reliability of 99.99974% of total energy delivered. Ofgem incentivises National Grid to improve reliability, and in 2009-10 they reported a marked reduction in 'energy unsupplied' by National Grid.

**Distribution** – DNO incentives are designed to reduce the number and duration of interruptions to supply over Distribution networks. Since 'quality of service' incentives were introduced in 2001 by Ofgem, an average distribution customer would have experienced in total four interruptions in 5 years (2001-06), with an average duration of 90 minutes. Ofgem indicators show that in each of the last three years reported, the average number of electricity customer interruptions fell. In 2009-10, there were on average fewer than 80 customer interruptions per 100 customers and the average minutes lost were below 80 per customer<sup>77</sup>.

**Electricity System Security** - Ofgem's 2010 Sustainability Indicators (Theme 4) for 'Ensuring a secure and reliable energy supply' also report on Electricity System Security. **Indicator 13 - 'Security and Diversity of Supply – Market Response' and Indicator 14 – 'Future Supply Capacity Mix'** report that UK maximum demand represented 77% of all

<sup>74</sup> DECC – Statutory Security of Supply Report. HC 452. November 2010.

Also, Ofgem Sustainable Development Indicators. Theme 4. Ensuring a secure and reliable gas and electricity supply. November 2010.

<sup>75</sup> Economy 7 – 1.5 to 2 million active customers (or thereabouts). See footnote above on English House Condition survey 2008.

<sup>76</sup> Also, Distribution network security and voltage requirements under 'Engineering Recommendation P2/6 and the 'Electricity Safety, Quality and Continuity Regulations'.

<sup>77</sup> Ofgem. 50/11. 31 March 2011. Electricity Distribution Annual Report for 2008 – 09 and 2009-10 pp 17-19.

registered generation capacity in 2009. Capacity margins were historically high<sup>78</sup>, but the coming decade will see significant closures of coal, oil and nuclear plant.

**Value of Lost Load** is used both as a proxy for economic value, and potentially, as a price-cap in capacity markets, for example. In a recent paper on valuation and management of load reduction by Chris Harris, he notes that the short term economic value of lost load can be far higher than the average price of power. He says that: ‘Once we have embarked on a course of needing electricity, we are greatly inconvenienced if it suddenly ceases’<sup>79</sup>.

**Customer Research on Valuing Supply / Lost Load** – A 2009 Ipsos Mori poll for Ofgem<sup>80</sup> asked household customers how likely they would be to use their gas or electricity at different times, if it was cheaper at different times. There was a positive response in respect of water-heating and wet-appliance use. Another Mori survey of 2,000 respondents in 2010 for the University of Cambridge<sup>81</sup> asked about customer willingness to be flexible on deferred or interrupted appliance use. Against a range of suggested discounts, Mori asked about respondents’ willingness to :

- Run wet appliances longer
- Interrupt white appliances (fridges / freezers) – for 1 to 3 minute intervals
- Pre-set wet appliances – Have wet appliances pre-set to run only after 9pm
- Limit use of cooker – Have use of cooker / oven capped – so household unable to use it for 30-minute intervals more than 15 times a year during peak demand spikes.

Respondents claimed to be generally willing to accept proposed interventions of this kind - even for low-end discounts. The only real resistance was to interrupting / delaying use of cookers and ovens.

By contrast, the IHS Global Insight paper for DECC<sup>82</sup> notes that ‘consumers are unwilling to inconvenience themselves for a small financial saving when the effort / time required is high’ owing to the assumed high value placed upon time, and the use of electricity.

Despite the two Mori surveys noted above, there nonetheless seems to be relatively little comprehensive and / or systematic evidence on what value GB customers in 2011 in different economic sectors and in different localities (i.e. urban, rural) are likely to place on secure and uninterrupted electricity supplies – i.e. what value modern-day GB customers are likely to place on lost load.

It may be helpful to have a clearer understanding of how today’s customers value lost load - given dependence on IT, computing and electronic communications - including in more rural

---

<sup>78</sup> Due in part to the downturn.

<sup>79</sup> Value and Management of Load Reduction. Chris Harris. University of Bath. March 2010. P.3

<sup>80</sup> Ofgem Energy Issues 2009. Published February 2010.

<sup>81</sup> University of Cambridge. Electricity Policy Research Group. 2010 EPRG Public Opinion Survey: Policy Preferences and Energy Saving Measures. EPRG Working Paper 1122. Laura Platchkov, Michael Pollitt, Daid Reiner, Irina Shaorshadze. August 2011. Pp 36-43.

<sup>82</sup> IHS Global Insight. Demand Side Participation. Report for DECC. July 2009. P.3

areas - where until now some customers were relatively accustomed to some supply interruptions. Not least, future EMR moves to develop capacity-markets via contracts designed to incentivise both supply-side and demand-side participation, will need a good understanding of the value which different customer segments are liable to place on security of supply and lost-load. In turn, such insight will also give some additional clues on customer appetite for demand-response and load management – in particular the levels of ‘reward’ or ‘value’ which customers may seek to alter behaviour.

**Some questions to explore in later papers will be:**

How far do we know / understand for 2011:

- How different customers value security of supply / lost load?
- The trade-offs customers may make to pay less – including for a lower level of supply security?
- The value of lost load– for different customer segments (including home workers), for customers in different locations (e.g. urban / rural) - and at different times of day.
- Whether perhaps in the longer term with universal smart meters, extreme emergencies may have the potential to be managed more ‘smartly’ eg via **voluntary** load-management agreements, where the customer retained supply but perhaps at a lower maximum demand level. What might be the knock-on impacts for values in the balancing or capacity markets of such ‘smarter’ demand-led approaches to resilience and supply security ?

## 6. Variability of Demand<sup>83</sup>.

**GB electricity demand fluctuates seasonally, across the week and during the day.**

Historic data, together with long-standing forecasting techniques mean that GB electricity demand patterns are broadly understood and predictable across the system.

Typical seasonal profiles for GB electricity demand are summarised below.

<b>Winter Profile - Maximum &amp; Typical Weekday Profile</b> (Weekends – lower demands, lower peaks)	
00.00h – 03.00h	Time-switched and radio-teleswitched storage heating and water-heating equipment.
06.30h – 09.00h	Demand build-up to start of working day
09.00h – 16.00h	Plateau reflecting working day – mostly I&C demand
16.30h – 17.30h	Rise to peak to lighting load and increased domestic demand outweighs fall-off in I&C load
18.00h – 00.00h	Demand reduces during evening. During the evening >50 % is domestic load

**Table 5 GB electricity winter profile – maximum & typical weekday profile**

<b>Summer Profile – Typical Weekday</b>	
00.00h – 03.00h	Water-heating but no storage heating.
06.30h – 09.00h	Build-up to start of working day
09.00h – 16.00h	Plateau reflecting working day – mostly I&C demand
17.30h onward	Rise to peak to lighting load (later onset) and increased domestic demand outweighs fall-off in I&C load
19.00h – 00.00h	Demand reduces during evening. >50 % is domestic load
<b>Summer Sunday Profile – Minimum Demand</b>	
05.00h – 0600h	Summer minimum demand (mid-July).
11.30h-14.00h	Lunchtime cooking load

**Table 6 GB electricity summer profile – typical weekday**

There is significant fluctuation in demand each day and through the year. Cloud cover, wind-speed and external temperature are key determinants of variability in demand day-to-day, but are largely predictable.

Irregular events also influence demand, including extreme weather and TV pick-ups, but these are also predictable. Highest recorded GB demand was 60.1 GW on 10 December 2002. Largest pick-up was 3 GW immediately after the solar eclipse in August 1999, as everybody resumed work at the end of the eclipse.

<sup>83</sup> National Grid. Seven Year Statement. May 2011. Chapter 2, pp 2-3.

Plus – DECC. Energy Trends. September 2010. ‘Daily Variations in Electricity Demand and the Effects of the 2010 World Football Cup. pp 49-53

**Winter Peak 2010:** Maximum winter peak demand was ~58 GW at 17.30 hrs on 7 December 2010 (ACS average-cold-spell peak (i.e. weather-corrected) and unrestricted – i.e. without load management). Typical system winter peak ~52 GW on 17 November 2010, (and average demand for that day of 41GW).

**Summer Minimum Demand 2010** - Minimum summer demand was ~19GW at 05.30hrs on 18 July 2010. Typical system summer minimum demand was ~22.6 GW on 10 June 2010 (and average demand for that day of 33GW). Since 2006, summer minimum demands have reduced year on year. Likely reasons include more distribution connected generation, summer shut-downs by industrial users, and more price-driven energy efficiency<sup>84</sup>. The daily minimum occurs around 05.00h to 06.00h throughout the summer.

**Summer Peak** – Summer peaks move throughout the summer. In April and May, demand is fairly flat across the working day, but, subject to warm weather, demand may peak during the afternoon. In June, July and August demand may be reasonably flat from 08.00h to 18.00h – but with a daily lunch-time peak at mid-day. In September and October, daily peak occurs in the evening due to lighting. A developing trend seems to be some local summer peaking due to air-conditioning and chilling loads in major cities such as London.

See below. NG SYS Fig 2.1 Summer and Winter Daily Demand Profiles in 2010-11.

See below NG SYS 2011 - 2.2 Weekly Maximum and Minimum Demands in 2010-11

Different customer groups make up different proportions of peak-load<sup>85</sup>. Ofgem made the following estimates about contributions to peak-load, treating the period 15.30hrs to 19.30hrs as peak:

Estimated Contribution by Customer Type to Peak-Load– 15.30hrs – 19.30hrs for selected autumn and winter days <sup>86</sup> .	
Customer-Type	Percentage contribution to peak (GW)
Interruptible I&C	3.8 %
Firm I&C	16%
SME	30.2%
Domestic	50 %
Total	100%

**Table 7 Estimated contribution by customer type to peak-load**

Ofgem also estimates that in the evening, around half of all electricity demand comes from domestic customers<sup>87</sup>. In practice, this may vary depending on the time of year.

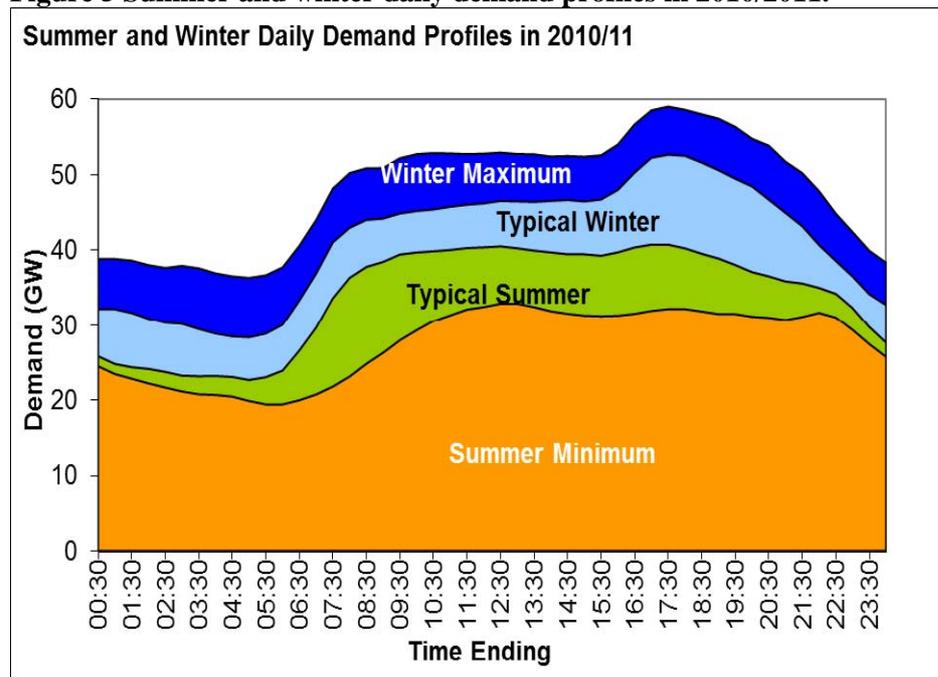
<sup>84</sup> National Grid. Summer Outlook Report 2011. P.29.

<sup>85</sup> IHS Global Insight. Demand Side Participation. Report for DECC. July2009. P.12

<sup>86</sup> Ofgem. Demand Side Response. July 2010. Appendix 2. P. 50.

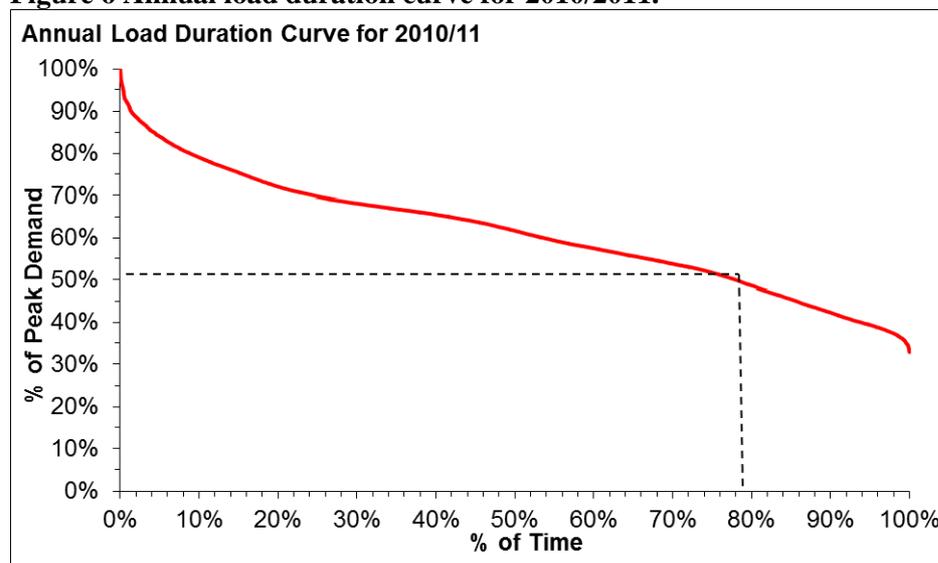
<sup>87</sup> Ofgem. Demand Side Response. July 2010. P 8. Para 1.10. Ofgem analysis for Project Discovery.

Figure 5 Summer and winter daily demand profiles in 2010/2011.



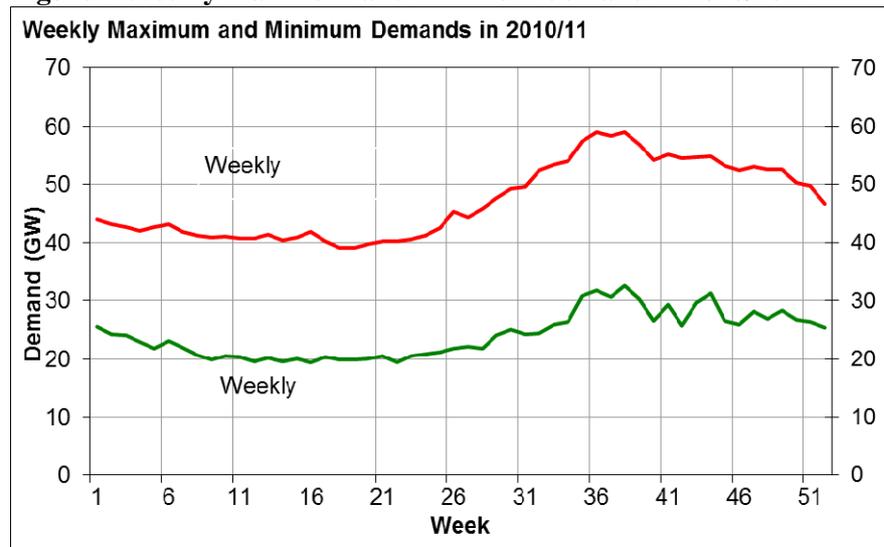
Source: 2011 National Electricity Transmission System Seven Year Statement

Figure 6 Annual load duration curve for 2010/2011.



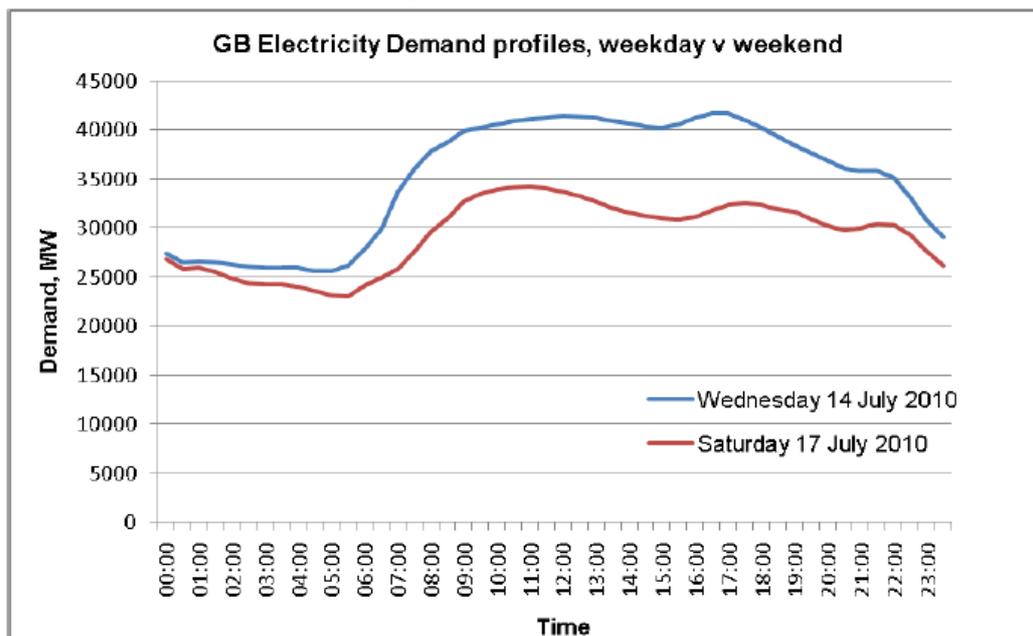
Source: 2011 National Electricity Transmission System Seven Year Statement

**Figure 7 Weekly maximum and minimum demand in 2010/2011**



**Source:** 2011 National Electricity Transmission System Seven Year Statement. (NB: Year runs April to March).

**Figure 8 GB Electricity demand profiles, weekday and weekend.**



**Source:** DECC Quarterly Energy trends, September 2010, p.38

6. **Predictability** – a key characteristic of GB electrical load today is that it is largely predictable. Electricity system management is planned and predicted on a probabilistic basis. Long- and short-term forecasts are made of how much electricity demand there is likely to be at what time of day. Forecasts are made both by National Grid and informed by suppliers and other system users, based on historic consumption and adjusted by other variables including: weather forecast; economic growth; fuel prices; household demographics; industrial and commercial loads; embedded generation development; energy efficiency measures; emerging technologies (e.g. heat pumps, electric vehicles).

Overleaf, is an illustration of one recent example of an ‘irregular’ event with largely ‘predictable’ demand, successfully managed on the day by the system operator.

Going forwards, as more distributed generation connects, and also, with the smart meter roll-out, as the capability for time-varying tariffs develops, and as new load management approaches are developed, this current relatively stable attribute of GB electricity demand – ie its relative predictability - looks set to become more complex.

This greater uncertainty in predicting electricity demand day-by-day will coincide with an increasing need for improved electricity demand forecasts and a better understanding of how electricity is used in the economy, by whom and when. For example, under any new capacity mechanism (regardless of whether a targeted or market-wide approach), electricity demand forecasts four years out, will determine the volume (and possibly also the price) of capacity to be contracted or tendered (either supply- or demand-side capacity).

Figure 9 - Forecasting Electricity Demand – Royal Wedding Day. 29 April 2011  
Source. National Grid.

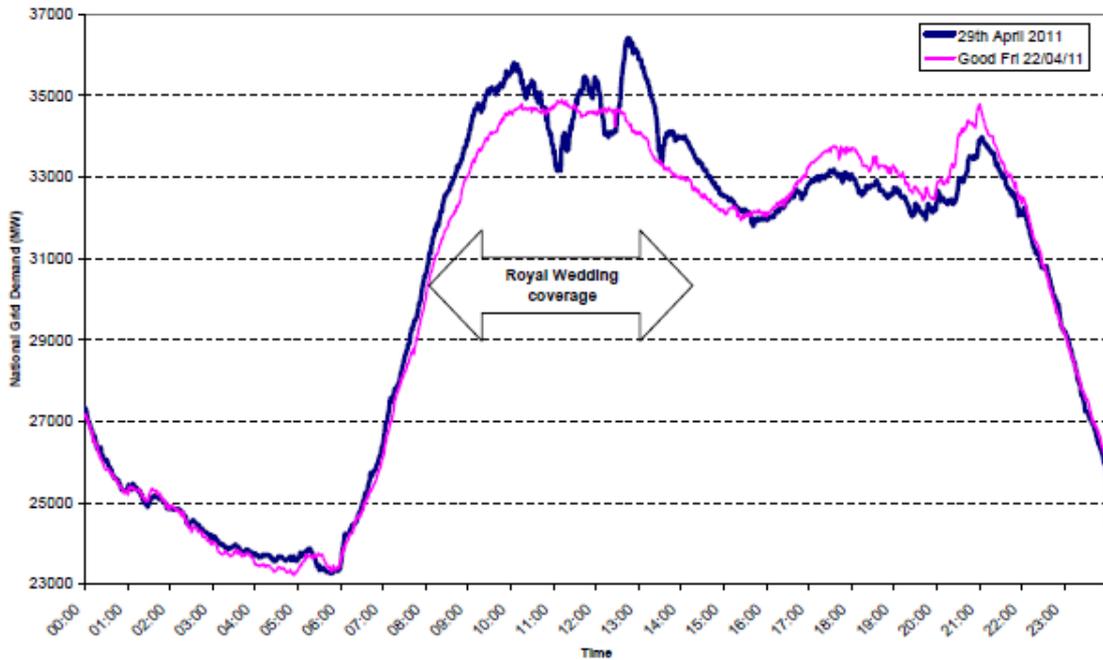
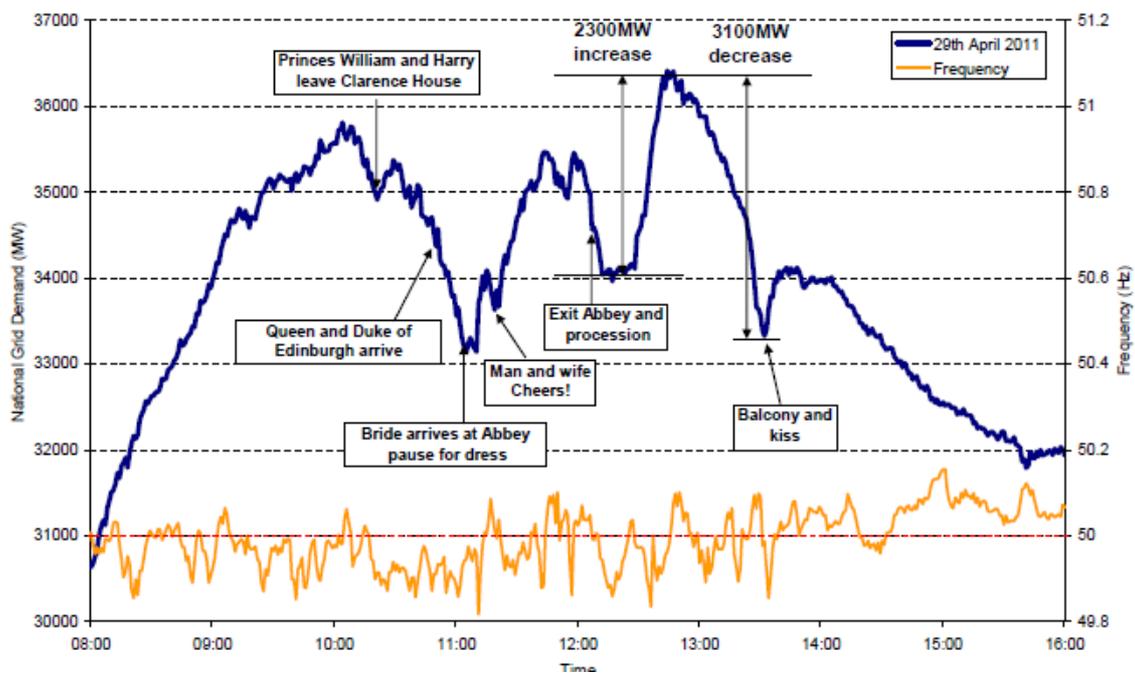


Figure 10 - Royal Wedding 29 April 2011. Demand Outturn and Frequency  
Source National Grid

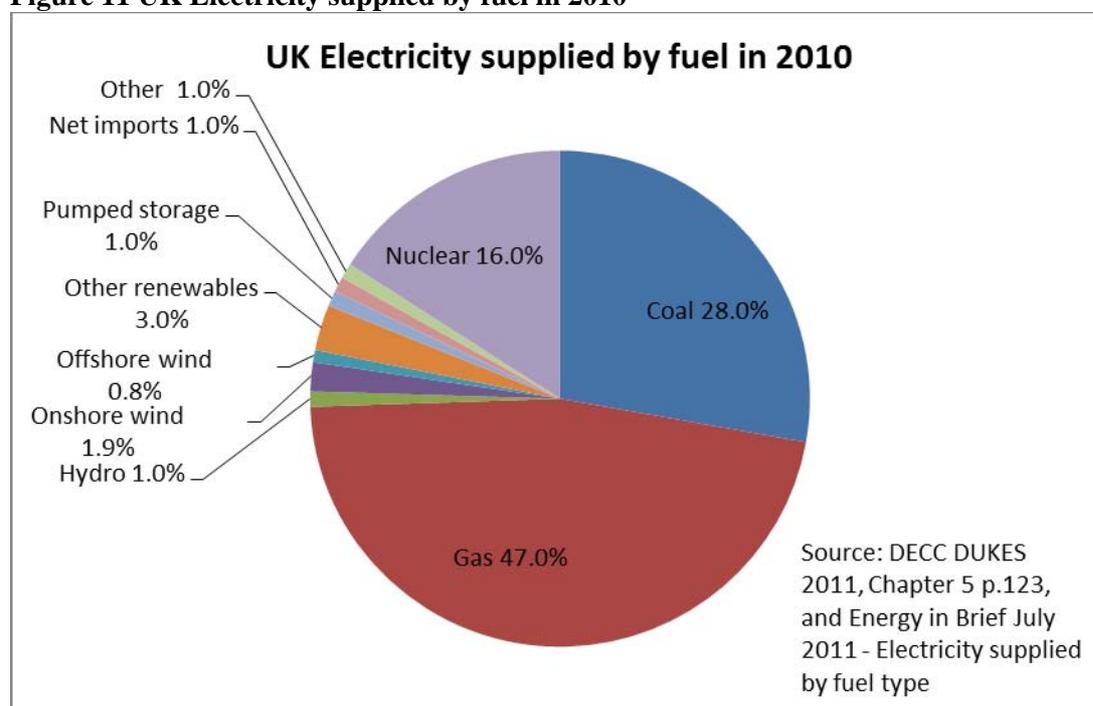


## 7. How Load is Met – the need for flexibility

Over the course of a day, demand is met by plant available to the system. Base-load (e.g. nuclear) generates continuously (long start-ups, low marginal costs, relatively inflexible). Wind operates whenever possible due to the way it is incentivised by the Renewables Obligation, but also may be variable in output. In response to prices in the electricity market- and in the balancing-mechanism, coal and CCGT currently provide system flexibility. Hydro, pumped storage and OCGT are particularly responsive. The demand-side also provides some flexibility (see section 9 below on Load Management).

Shares of electricity-supplied by fuel in 2010 are shown in Figure 9 Below (total 364 TWh in 2010)<sup>88</sup>.

**Figure 11 UK Electricity supplied by fuel in 2010**



A 2010 Poyry<sup>89</sup> study for the CCC, carried out a detailed modelling study of how power system flexibility helps to match the profile of generation to demand, either by changing the pattern of generation or by varying demand. Poyry explore from a technical and economic stance, the scope for future flexibility from generation, interconnection and storage, as well as from demand.

<sup>88</sup> DECC – DUKES. July 2011. Section 5 Electricity. Table 5.2 p.122. (365 TWh of net electricity generation). Also, 'UK Energy in Brief'. July 2011. Electricity Supplied by Fuel Type. 2009 & 2010. p.26.

<sup>89</sup> Options for Low-Carbon Power Sector Flexibility to 2050. A report to the Committee on Climate Change. October 2010. p. 62. Also, Poyry Table 10 p 65 'Overview of Strengths and Weaknesses of Each Option for Flexibility'.

Poyry define flexibility as; ‘a change in behaviour over an appropriate timescale that helps electricity demand to be met at least-cost whilst complying with emission targets’.

They say that flexibility ‘options’ differ in a number of key characteristics:

- Quantity (both annual volumes and maximum hourly contributions) ;
- Speed ;
- Duration ;
- Availability – both regular patterns and unexpected outages ; and
- Costs – both investment and operational

In addition to these characteristics noted by Poyry, physical location is also a key attribute of flexibility – especially for the Networks.

## 8. Demand-Side Flexibility

Both IHS Global Insight<sup>90</sup> and Poyry<sup>91</sup> acknowledge uncertainty in how much electricity demand will be flexible in practice. Poyry identify four key sources of flexible electricity demand:

- Rescheduling / shifting demand
- Fuel substitution / switching – e.g. for example switching to gas water-heating
- Storage – to de-couple electricity production and demand
- Providing electricity back into the system – either from storage or from embedded generation.

Poyry also note the important role of price signals in incentivising flexible generation or flexible load<sup>92</sup>.

KEMA identify seven opportunities for Demand Response as follows<sup>93</sup>:

- **Retail energy deals for consumers** – load-shifting following smart-meter roll-out (including long-term potential for dynamic pricing).
- **Household load-management** – e.g. load-management of heat-pump and electric vehicle load to avoid total network loading, incentivised to remain within power-flow and voltage quality limits, avoiding network reinforcement costs and disruption.
- **DNO constraint management** - avoid local network overloading through aggregation to enable constraint management, defer reinforcement; provide voltage support, local balancing and domestic-level storage.
- **TNO constraint management** - avoid regional and national network overloading – as above at higher voltage
- **System Operator Services** - balance variable generation at national level – by providing Operational Reserve, Black Start and Reactive Power services.
- **Supplier Balancing** – suppliers to improve balancing positions for both trading and balancing mechanism.
- **Deferred / Avoided capital cost of new peaking power plant.**

A further recent report commissioned by DECC from Poyry and the University of Bath<sup>94</sup> modelled two demand-side scenarios in 2030 and 2050 to evaluate which might deliver greater cost-efficiency and security to the electricity system as a whole. The alternative scenarios are (1) optimising operational cost-efficiency in the wholesale markets by balancing wind variability with responsive demand and (2) optimising network investment through reduced customer peak demand. Modelling out to 2050, Poyry conclude that the likely costs of each alternative are comparable - but that scenario 1 may bring additional benefits of electricity system security (because success does not depend on suppressing peak demand).

<sup>90</sup> IHS Global Insight. Demand Side Participation. Report for DECC. July2009. P.3

<sup>91</sup> Poyry. Options for Low-Carbon Power Sector Flexibility to 2050. A Report for the CCC. p 80

<sup>92</sup> Poyry. Options for Low-Carbon Power Sector Flexibility to 2050. A Report for the CCC. p 108.

<sup>93</sup> KEMA. Report 1. p 18

<sup>94</sup> Demand Side Response: Conflict Between Supply and Network Driven Optimisation. Poyry and University of Bath. Report to DECC. November 2010. Published August 2011.

## 9. GB Load Management 2010

GB load-management / demand-side schemes are operated today by: National Grid as the GB System Operator; by Suppliers (TRIAD management; time-varying pricing for I&C customers); and by the Transmission and Distribution Networks.

- **National Grid** - contracts with the demand-side to help balance / regulate the national electricity system in short-term operational timescales. For their current 2011/12 'Operating Reserve' requirements of 4.7 GW, National Grid has non-Balancing Mechanism demand-side contracts for ~1000 MW – i.e. some 20-25% of Operating Reserve. However, around two-thirds of this is assumed to entail a switch to back-up on-site generation. 'True' demand-side services contracted to National Grid for Operating Reserve are understood to be nearer to 350 MW, equating to a more modest 7.5% of total Operating Reserve Services currently.
- **Suppliers - Triad Management by Suppliers** – contributes around 0.5 – 1 GW (see Table 9 below for explanation). **Suppliers** – also offer a variety of contracts to half-hourly and non-half hourly settled I&C customers or their brokers – which may incorporate time-varying pricing for base-load, peak and seasonal pricing.
- **GB Distribution Networks** - are exploring a variety of customer incentives and approaches to peak-avoidance, including working with aggregators and also through LCNF, to avoid peak-related capital expenditure for network re-inforcement which wide-scale connection of PV, heat pumps and electric vehicles might otherwise require.

The following tables set out the different load management schemes and approaches today across the GB electricity system.

<b>Table 8. System Operator. Balancing Services/ Operating Reserve for Energy<sup>95</sup></b>				
<b>Service Need</b>		<b>Service Provided</b>	<b>Volume / What</b>	<b>Comment</b>
<b>Frequency Response</b> – National Grid Licence Obligation to control frequency at +/- 1% of 50hz at all times				
<b>Frequency Control by Demand Management (FCDM)</b>  and  <b>Firm Frequency Response (FFR).</b>  (1) To contain system frequency in the event of a loss of either generation or demand (2) To correct short-term frequency variations due to delay in balancing actions taking effect.  Can be Dynamic – or Non-Dynamic	<ul style="list-style-type: none"> <li>• Delivery in 10-30 seconds</li> <li>• Sustain for 10-30 minutes</li> <li>• 3 MW minimum</li> <li>• Can be aggregated</li> </ul>	<b>Dynamic Frequency</b> – automatic changes to load, in response to second-by-second changes in system frequency.  <b>Non-Dynamic Frequency</b> – service triggers at a defined frequency deviation.	FCDM – 49.7Hz ~150 MW  Examples: Dynamic – 3-5MW of commercial heating load ; Non-dynamic – smelting interruption	RL Tec – frequency response contract with National Grid (RL Tec deploy Heating & Ventilation units across 200 Sainsbury stores – March 2011).
<b>Voltage Control</b>	Involuntary emergency reduction in demand. Up to 5% reduction feasible	Emergency Measure. Voltage reduction - no attributed commercial value		No more than 1-2 hours - or may damage sensitive equipment. Must maintain quality of supply.
<b>System Operator Reserve</b> – ‘regulating’ services which secure more generation – or demand-downturn – following unforeseen increase in demand – or generator non-availability.				
<b>Fast Reserve</b>	<ul style="list-style-type: none"> <li>• Delivery in 2 minutes</li> <li>• Sustain for 15 minutes</li> <li>• 50 MW minimum</li> </ul>		Teleswitched Economy 7 storage heating – ~250 MW	
<b>Short Term Operating Reserve (STOR)</b>  For B-M & Non-B-M units (Balancing Mechanism Unit).	<ul style="list-style-type: none"> <li>• Delivery in 20 minutes (max 4 hours)</li> <li>• Sustain for 2 hours</li> <li>• 3 MW minimum</li> </ul>	<ul style="list-style-type: none"> <li>• From one or more sites</li> <li>• Aggregation possible</li> <li>• Competitive Tender</li> <li>• Service can be provided on committed or flexible basis.</li> </ul>	Example – Industrial process interruption	May entail substitution to on-site generation

<sup>95</sup> Sources : National Grid publications and website.

Also, report for DTI. URN 06/1432. ‘Reducing the Cost of System Intermittency Using Demand-Side Control Measures’. 2006. IPA Consulting, Econnect Ltd & Martin Energy.

<b>Supplier Demand Management</b>				
<b>Service Need</b>		<b>Service Provided</b>	<b>Volume / What ?</b>	<b>Comment</b>
<b>Transmission Network - TRIAD Management</b>	The annual £/MW network charge payable by licensed Suppliers to National Grid (TNUoS - Transmission Network Use of System Charges), are in part, calculated on the basis of the Supplier's maximum peak load. This is calculated each year by taking the average three half-hours of highest system peak demand –the TRIAD. The aim of TRIAD charging is to incentivise Suppliers to curtail their maximum load (i.e. their customers' load) at peak, to defer network re-inforcement.	Suppliers contract directly – or may use aggregator – for TRIAD-related load-curtailement from their customers.	0.5GW – 1 GW reductions in demand are typically experienced in TRIAD periods (~ 1-2% of peak demand).	Triad management is restricted to a suppliers' larger I&C customers (Half-Hourly / other Load Profiles Classes).
<b>Transmission Network Constraint Management</b>	Short-term or long-term DSM responses – instead of (temp) network constraint measures (e.g. FACS, SVCs ).	Short term measures to deal with Transmission network outages / maintenance etc.		

**Table 9 Supplier Demand Management**

Supplier Demand Management – Retail Tariffs					
Service Need		Service Provided	Volume / What ?	Comment	
<p><b>I&amp;C Customers</b></p> <p>Suppliers seek reduced operating costs through management of (1) energy procurement risk and (2) imbalance charges ~60% of a business customer's total end-bill is likely to be energy related.</p>		<p>Suppliers / brokers offer I&amp;C customers a variety of fixed and variable contracts. These contracts are likely to include some time-varying pricing, including e.g. day, night, seasonal blocks.</p> <p><b>Example:</b> Government Procurement Service offer all public sector bodies opportunity to access power in the half-hourly and non-half hourly markets – <b>including via 10MW hourly 'baseload' blocks - 19.00hto 07.00h.</b></p>	<p><b>Half-Hourly Metered 100kW+ I&amp;C Customers:</b> a variety of base-load, peak and seasonal pricing available.</p> <p><b>Commercial Profile Classes 5-8 Not half-hourly settled</b> - volumes on time-related pricing unknown.</p> <p><b>Small Commercial Profile Classes 3&amp;4</b></p>	<p><b>117,000 100kW+ customers:</b>~50% of all electricity consumed (150TWh annual consumption).</p> <p><b>Commercial: Non-Half Hourly Profile Classes 5-8</b> – (16TWh annual consumption)</p> <p><b>Small Commercial Profile Classes 3&amp;4<sup>96</sup></b> 35 TWh annual consumption.</p>	<p>Not known what I&amp;C volumes already on time-related pricing to some degree. All 100+kW customers on half-hourly settlement - so accurate billing benefits available to suppliers.</p> <p>Load Profile Class 3-8: ~ 2.5 million non half-hourly metered customers – profiled for settlement purposes. Supplier may therefore not re-coup full value of demand-side actions / investment for this customer group.</p> <p>Almost one-quarter of small commercial annual consumption (Load Profile 4) is estimated to be off-peak.</p>
<p><b>Household / Micro Business Customers</b></p> <p>Chiefly historic off-peak tariffs linked to Economy 7 &amp; 10 storage heating. Possibly 1.5 to 2 million customers – many off the gas grid.</p> <p>Some limited toe-in-water ToU tariffs – mix of non-smart &amp; smart</p>		<p><b>Off-Peak Night Units</b></p> <p>After midnight</p>	<p><b>Profile Classes 1&amp;2</b> 115 TWh total annual consumption – of which 25.5 TWh is offpeak.</p>	<p>Around 20% of annual household electricity supplied is already on an off-peak night tariff – mostly heating and some hot-water.</p> <p>Radio Teleswitch arrangements due to end in 2013.</p>	

**Table 10 Supplier Demand Management – Retail Tariffs**

<sup>96</sup> Elxon website. 'Smarter Settlement – making the most of tariff innovation' March 2011 – and follow-up email exchange. September 2011.

<b>Distribution Networks</b>				
<b>Demand Management Charges by Distribution Networks</b> - to Suppliers, Other Networks, Generators (excl small micro-gen) and Large Demand.				
<b>Service Need</b>		<b>Service Provided</b>	<b>Volume / What ?</b>	<b>Comment</b>
<p><b>Use of System Charges</b> – allows cost-recovery by DNO of some of the fixed and variable costs of network investment, reinforcement, maintenance, repair and operation of the network. A new generic methodology implemented via a Common Distribution Charging Methodology (CDCM) – April 2010.</p> <p>Network charges for Customers in Load Profiles Class 1-8 typically include 2 elements.</p> <p><b>Fixed costs</b> – including a maximum demand / capacity element (p/kVA).</p> <p><b>Variable costs</b> – include a network usage element which includes a ToU element (p /kWh).</p>		<p><b>CDCM</b> – introduced ToU periods (p/kWh) in network-usage charges. The aim is to give suppliers (and their larger customers) a stronger message about the costs associated with network usage at peak / higher cost periods.</p> <p><b>Time of Use periods in Distribution Use of System Charges</b></p> <p>- <b>Half-Hourly Metered Customers on EV / HV &amp; LV networks. A three-rate Time of Use tariff (p/kWh) for Peak (Red), Standard (Amber) and Green periods (all other times).</b> NB – peak periods vary on different networks.</p> <p>- <b>Customer Load Profile Classes 1-8 on LV &amp; HV Networks :</b> Two-rate ‘Time Pattern Regime’. Day / Night Unit-Rate charges (p/kWh) for network usage – &amp; which vary subject to customer Load Profile.</p>	<p>Impact on customer usage - not known.</p> <p>Red periods: may impact end-bills of largest users with high peak usage, assuming their network charges ‘pass through’ directly – unless able to reduce or shift peak-usage.</p> <p>Since April 2010, some DNO use-of - system tariffs charged to suppliers for certain p/kWh day-rates may have increased (notably for households - Load Profile Class 1).</p>	<p><b>EV Networks</b> - ongoing regulatory debate on desirability / feasibility of introducing ‘locational’ element in Distribution Use of System charges - to incentivise location choice of distributed generators.</p> <p>Will suppliers wish to reflect more directly in their retail tariffs the cost differentials of network usage between day- and night rates? For households, only those customers on Economy 7 - or similar tariffs - can presently respond.</p>
<p><b>Non-Contestable Connection Charges</b> – allows 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).</p> <p>Common Connection Charging Methodology in discussion.</p>			<p>Statutory connection offers are on an economic-cost basis – and respond to level of required load – i.e. ‘required capacity’.</p>	<p>For the future, how to develop incentives for demand-reduction and demand-response to be valued in connection offers and in approaches to connection charging? [Not a regulated activity].</p>

<p><b>DNO Schemes for Location Specific Problems e.g. Substations</b></p> <p><b>Example – Electricity North West<sup>97</sup></b></p>	<p>Substation peaks 16.30h – 18.30h.</p> <p>For avoided opex &amp; deferred capex –</p> <p>For fault management.</p>	<p>ENW I&amp;C customer research - initial customer expectations on payment for an offer of load-management service, exceeded the avoided costs of network reinforcement.</p>	<p>ENW – Of 42 load-related network problems - identified 10 opportunities for deferred network reinforcement by DSR.</p>	<p>Electricity North West – with an Aggregator</p> <p>New 5-year load-management trials in Bury &amp; Stockport</p>
<p><b>LCNF Projects<sup>98</sup></b></p>	<p>Aim :</p> <ul style="list-style-type: none"> <li>• deferred capex</li> <li>• low-carbon technology experience</li> </ul>			<p><b>Northern Powergrid /Centrica – Customer-Led Network Revolution</b></p> <p><b>UKPower Networks – Low Carbon London</b></p> <p>Others</p>
<p><b>Other projects</b></p>			<p>SSE<sup>99</sup> - Shetland NINES Pilot – to evaluate, network stability and control using thermal storage to balance wind intermittency. Wind to thermal stores in households – hot water tanks; storage heaters. Also large non-household thermal stores / batteries.</p> <p>Npower / Indesit CERT trial - 300 to 1,000 fridges &amp; freezers.</p>	<p>September 2011 – Ofgem agree to SSE pilot to inform submission of an Integrated Plan in 2013 to manage supply and demand on Shetland.</p> <p>To evaluate potential for frequency response from household fridges and freezers.</p>

**Table 11 Distribution Networks**

<sup>97</sup> ‘Achieving Effective Customer Engagement: the experience of Electricity North West’. Presentation by Tony McEntee. ENW. 25 May 2011. [www.networkrevolution.co.uk](http://www.networkrevolution.co.uk)

<sup>98</sup> Presentations by Northern Powergrid Electric, Jim Cardwell and British Gas, Ellen Fraser. 25 May 2011. [www.networkrevolution.co.uk](http://www.networkrevolution.co.uk) website. Also UK Power Networks – Low Carbon London overview by Sara Bell. 25 May 2011

<sup>99</sup> Presentation by Stewart Reid. SSE. 25 May 2011 [www.networkrevolution.co.uk](http://www.networkrevolution.co.uk) website and Ofgem letter 15 September 2011 ‘Decision on funding for the Shetlands Northern Isles New Energy Solutions (NINES) Project.

**Common Distribution Charging Methodology<sup>1</sup>**

In very broad terms, transmission and distribution network charges total around 20% of the final customer bill. Suppliers sought for their use of system charges payable to DNOs to be structured and calculated using a generic model for GB. Ofgem gave DNOs a new licence condition to create a Common Distribution Charging Methodology (CDCM) for their LV<sup>1</sup> and HV<sup>1</sup> networks, which was adopted from April 2010.

The CDCM sets out agreed principles and a common approach to tariff structures by which DNOs charge suppliers, other networks, distributed generators and large customers over a certain size - for the fixed and variable costs of providing and operating their distribution network.

A core aim was to introduce more cost-reflectivity and consistency in distribution network charging. This included: improving the allocation of costs between network levels (LV, HV and EV); improving the cost-allocation for fixed costs (charged as p/kVA) – based on the contribution to simultaneous maximum demand of each customer group (i.e. by each Load Profile Class; by Half-Hourly Metered Customers; by generator); by improving the cost-allocation relating to network-usage (charged as p/kWh) – including differentiated charges for use at peak- and non-peak times.

From April 2011, DNOs also adopted an EV<sup>2</sup> Distribution Charging Methodology (EDCM), which introduced a generic GB-wide approach to the structure of site-specific use of system tariffs.

A further aim of a common charging methodology was to improve the match between DNO charges and allowed revenues under the Distribution Price Control.

1. Ofgem. 114/09. 'Electricity distribution structure of charges project : DNO's proposal for a common methodology at lower voltages'. September 2009.
2. Extra High Voltage - >22kV and <132kV

**Eirgrid Example – Winter Peak Demand Reduction Scheme**

There are many electricity peak and load-management schemes run by system operators and others elsewhere.

One peak-avoidance scheme of possible interest has been run by Eirgrid, the Ireland System Operator, since 2003. Their Winter Peak Demand Reduction scheme involves a reliability / penalty payment offered for reliable flexible demand offered for a two-hour period on weekdays between 17.00h and 19.00h. In winter 2010-11, over 200 customers signed up for the scheme - around 10% of those eligible<sup>1</sup> - with a typical daily peak reduction of ~100 MW on a maximum system demand of ~ 6GW. The scheme operates in the all-Ireland electricity pool<sup>2</sup>.

There are other demand reduction schemes in Ireland, for example, a Winter Demand Reduction Incentive run by Electric Ireland (ESB Supply). Customers are unable to participate concurrently in both schemes.

1. Customers must have on-line quarter-hour meters.
2. Eirgrid presentation. Sean Connolly and Siobhan McHugh, 18 & 19 May 2011. ESNA conference, London.

## 10.Despatchable and Deferrable GB Load

### Introduction

Some practical questions which this project will address over the coming year are about the availability of flexible and / or despatchable or deferrable load in the current GB electricity system. These will include questions such as :

- What is the unexploited demand-side potential today - and what are its chief characteristics and capabilities? What technical and commercial steps are needed to deliver this potential?
- Is the electrical load which could offer demand-side solutions today, more suited to providing the kind of operational security sought by National Grid in system balancing (i.e. frequency response, reserve) – rather than peak avoidance?
- Are suitable characteristics available from today's electrical load to balance wind intermittency, variability, and rapid changes in supply-side output? If not, which new electrical load can – or will – successfully deliver those characteristics?
- For peak-avoidance, what key demand-side characteristics are necessary – e.g. firm, long-duration etc.
- What overlap – if any - is there in the demand-side characteristics and services which suppliers and networks may need for delivery of peak-avoidance in the capacity markets or the networks – and those which the system operator may need for operational security / balancing?

The following sections start to unpack some of these issues at a high level. This project will return to all of these issues in more detail in future papers.

## Is There Unexploited Demand-Side Potential Today?

Responses received by National Grid from suppliers, customers, aggregators and others to their consultation<sup>100</sup> suggested that 3 GW of discretionary / deferrable demand may be feasible by 2020<sup>101</sup>. Much of this (but not all) would come from the kinds of electrical equipment and appliances already common-place today - but enabled and managed by new controls and software.

National Grid themselves expect a somewhat more conservative ~2 GW of DSR to be feasible by 2020 (see section 12).

## Flexible / Variable Load - System Operator

As noted, today National Grid has around 150 MW of fast response and around 1000 MW of contracted load-management in its Operating Reserve portfolio, representing 20-25% of its current total Operating Reserve requirement. Possibly around 650 MW of this contracted demand-side Operating Reserve entails a switch by the demand-side provider to on-site back-up generation. The 350 MW of ‘true’ demand-side response represents ~8% of National Grid’s 2011 Operating Reserve requirement of 4.7 GW<sup>102</sup>.

## Peak Avoidance - Suppliers and Networks

The 500-1,000 MW of TRIAD demand reduction presently achieved by customers for their suppliers at winter-peak equates to between 0.8% to 1.7% of the 58 GW ACS maximum winter-peak demand experienced in 2010.

Subject to major health-warnings, there are a number of possible pointers to suggest unexploited potential for more GB despatchable or deferrable load – especially, presently, for peak avoidance. These include:

- **I&C Load - Eirgrid SO Winter Peak Reduction Scheme<sup>103</sup>** – Direct comparisons may well be inappropriate (for example, peak-avoidance is incentivised by an administered price and ‘products’ sought by Eirgrid are limited in nature). Nonetheless, there seems to be around 1.5% of total peak-load actively participating in the Eirgrid scheme on a daily basis throughout the winter months (on the face of it delivering an equivalent peak-load reduction at the top-end of the three annual TRIAD reductions in GB).

<sup>100</sup> National Grid. Operating the Electricity Transmission Networks in 2020 (Update). June 2011.

<sup>101</sup> i.e. ~40 % of the expected 7.3 GW Operating Reserve requirement in 2020 – and / or ~5-6% of typical winter peak demand.

<sup>102</sup> 350 MW amounts to 0.7% of a typical winter system peak demand of 52 GW.

<sup>103</sup> Eirgrid presentation. Sean Connolly and Siobhan McHugh. 18-19 May 2011. ESNA conference. London.

- **Household and SME Load - Ireland Smart Meter Trial<sup>104</sup>** – findings for households on time-of-use tariffs with customer-stimuli were an 8.8% reduction at peak (and a 2.5% demand reduction). Existing off-peak customers were excluded from the trial. One possible difference is that there is more electric water heating in Ireland than in GB. Findings (not statistically significant) for SMEs trialled were a 2.2% reduction at peak (and a 0.3% demand reduction overall, with a 0.9% day-time reduction).
- **Household Load - GB Energy Demand Research Project<sup>105</sup>** – somewhat more limited nature of findings, but suggests an electricity peak-load reduction in response to a time-of-use tariff in a range from 7-10 % (greater shifting at weekends and for smaller households) and an overall electricity demand reduction of 2-4 % with concerted advice.

### Sector Contribution to Peak Demand – and Potential to Peak-Shift

As noted, Ofgem made the following estimates of contribution by customer-type to autumn and winter evening peak-load:

<b>Estimated Contribution by Customer Type to Peak-Load– 15.30hrs – 19.30hrs for selected autumn and winter days<sup>106</sup>.</b>	
<b>Customer-Type</b>	<b>Percentage contribution to peak (GW)</b>
Interruptible I&C	3.8 %
Firm I&C	16%
SME	30.2%
Domestic	50 %. Households have a peaky load. Ofgem calculate that households constitute around half of winter evening peak-load – but domestic customers consume ~30 % over a year of total day-rate ‘unrestricted’ electricity supplied (86 TWh out of 281 TWh)
Total	100%

**Table 12 Estimated contribution by customer type to peak-load**

<sup>104</sup> CER. (Commission for Energy Regulation. Ireland). Electricity Smart Metering Customer Behaviour Trials (CBT) Findings Report. CER11080a. 16 May 2011.

<sup>105</sup> Energy Demand Research Project. Final Analysis. Gary Raw & colleagues. AECOM for DECC. June 2011.

<sup>106</sup> Ofgem. Demand Side Response. July 2010. Appendix 2. P. 50.

For the modelling in their 2010 DSR report, Ofgem assumed that households have a greater potential to peak-shift than other customers.

- **Household customers** – 5-15% peak-shift<sup>107</sup>.
- **SME customers** – 5% peak-shift
- **Firm I&C customers** – 5%. (Additional to interruptible I&C customers).

### **Household Sector – Current Flexible Potential**

Sustainability First in its 2010 report<sup>108</sup> estimated that around one-fifth to one-quarter of today's household electrical appliance load could be discretionary or potentially price-responsive (not including current electric heating and some water-heating).

National Grid have modelled domestic appliance-use (wet appliances, refrigeration, ovens) by time-periods throughout the day. They estimate that ~4 GW in total of domestic wet appliances and refrigeration may operate between 16.00h to 20.00h. Of this, they assume that some 200 MW (i.e. 5% of the total demand in that 4-hour window) could be discretionary<sup>109</sup>.

### **Industrial and Commercial – Current Flexible Potential**

Ofgem note that there is no consensus within industry about the level of demand-side response that can be assumed as of today<sup>110</sup>.

National Grid anticipate that the commercial / SME sector in particular is most likely to provide much of the new flexible load-management services in the next 5 years. The Carbon Reduction Commitment has contributed to many businesses becoming increasingly proactive and conscious of their energy management<sup>111</sup>.

### **Initial Conclusion on Demand-Side Potential of Different Economic Sectors**

**I&C Customers** - Given that around two-thirds of all GB electricity load is concentrated among some 2.3 million customers (section 2), common sense suggests that the I&C sector has untapped despatchable or deferrable electricity load which could be incentivised and accessed.

Despite Eirgrid's positive experience with daily peak-avoidance for I&C customers however, initial discussion and analysis suggests that relatively little is known in GB about the true flexibility, despatchability, or elasticity of I&C electrical load – nor the general customer

<sup>107</sup> Based on IHS Global Insight. Report for DECC. 'Demand Side Participation'. 2009.

<sup>108</sup> Owen G and Ward J. 'Smart Tariffs and Household Demand Response for Great Britain'. March 2010. p.58

<sup>109</sup> National Grid. Operating the Electricity Transmission Networks in 2020 (Update). June 2011. Table 12.

Potential Demand Response from Domestic Appliances (MW) p.89

<sup>110</sup> Ofgem. Demand Side Response. July 2010. p. 51

<sup>111</sup> Operating the Electricity Transmission Networks in 2020. National Grid. June 2011. p.88 para 15.12. See section 12 below for National Grid 2020 modelling.

appetite to participate either to (1) provide flexible operational services such as Frequency and / or Reserve and / or to provide (2) peak avoidance to the networks, or into a new capacity market.

**This project will investigate in the coming months - through interviews and a small sample survey - the scope for GB Industrial & Commercial despatchable electrical load - including its likely location on the networks and perceived customer-barriers to realising this potential resource.**

**Households** – Given that around half of all winter evening peak-consumption is apparently by households, and given the results of the Ireland smart meter trials, the GB smart meter roll-out to households will provide the opportunity to explore householders’ true appetite for more flexible consumption patterns and peak-load management.

**Interactions Between Customer Sectors** – going forwards, issues which the project will aim to understand further include:

- Whether the different uses of electricity and the associated consumption patterns – (across the day, seasonally) - of different customer groups (I&C, households) lend themselves to providing particular electricity demand-side services and ‘products’. For example, whether I&C customers will be more likely to provide fast-response, operating reserve and other balancing services to National Grid? In the long-run, whether households will be more likely than other customer groups to provide services for avoided-peak – either to the networks and / or – in due course – to the capacity markets ?
- The potential impact on underlying and peak-related costs for the household sector, if early policy and commercial effort were to be directed chiefly at delivery of I&C demand response and demand reduction.

## 11. Valuing System Flexibility and Avoided Peak Load

Today, there are only a relatively few arrangements and mechanisms in the GB electricity market by which demand response is currently valued in the GB electricity system (e.g. STOR, Triad peak avoidance). Moreover, there is relatively little by way of transparent demand-side pricing as a means to enable potential providers of demand response to know what their offer of flexibility or peak-avoidance may be worth to the electricity system, at a given time or at a given location. Some current pointers to the possible value of both flexibility and of avoided GB Peak Load in today's electricity system are set out below.

However, these 'pointers' to possible value, outlined below, are of limited help as a guide to understanding the value of new demand-side products and services yet to be developed and / or demand-side services in the future GB electricity system, in, say 2020 or 2025.

**This project will explore these and other questions about the potential value which demand response could bring to the electricity system going forwards – both in terms of system flexibility and in terms of peak avoidance – in subsequent papers.**

### Pointers to Value of Demand-Side Flexibility to System Operator.

**National Grid** – give an indicative £/MWh price for Short Term Operating Reserve – presumably available equally to both demand and generation. They indicate an average cost of their Operating Reserve requirement of 4.7 GW in 2010-11 at £102 million – and note a STOR price (short-term operating reserve) of £350/MWh in 2010/11 (against a power price of £41.82/MWh). By 2020, they indicate a possible Operating Reserve requirement of 7.3 GW with a cost of £945m (possible STOR reserve price of £685/MWh in 2020/2021 (against an assumed power price of £84/MWh)<sup>112</sup>.

### Pointers to Value of Peak-Avoidance to Suppliers and / or Networks

**The Ofgem DSR paper**<sup>113</sup> - modelled and undertook an indicative calculation of the economic value of a 5% and 10% GB peak-shift. Ofgem noted that their calculation was likely to be conservative. Estimated savings were:

- **Generation** - annual capital-cost savings. 5% peak reduction – in the range £129-£261m pa. 10% peak reduction – in the range £265-£536 m pa. The total generation savings calculated, also included an estimate for short-run wholesale commodity-cost savings<sup>114</sup>.
- **Load-related network reinforcement** - capital savings estimated at £14m pa (5% peak-shift) – and £28m pa (10% peak-shift)<sup>115</sup>.

<sup>112</sup> National Grid. Operating the Electricity Transmission Networks in 2020. P. 31 and p74

<sup>113</sup> Ofgem. Demand Side Response. A discussion paper. 82/10. July 2010.

<sup>114</sup> Wholesale cost savings - £0.4m to £1.7m per day

<sup>115</sup> Load-related reinforcement was the only type of network-saving factored by Ofgem into their calculation

- **Carbon** - Ofgem also calculated a value for displaced CO<sub>2</sub> emissions<sup>116</sup>.
- **Demand-side competition with supply-side** - additional but unquantified benefits.

**Eirgrid Winter Peak Demand Reduction Scheme** – Reliability payment – Euros 224/MWh; Penalty for non-delivery - Euros 783/MWh<sup>117</sup>.

**Smart Meter Impact Household Assessment**<sup>118</sup> – The GB household smart meter Impact Assessment estimates that in the near-term some 20% of household peak-load may be discretionary. It estimates the economic benefit associated with household time-of-use to 2030 at £800 million. This sum splits 3-ways between: avoided short-run costs of energy (£121m); avoided generation investment (£653m) and avoided network investment (£29 m). The estimated avoided-peak benefit from household time-of-use does not include other savings – e.g. some carbon; potential smart grid benefits longer-term<sup>119</sup>.

**Networks – Avoided-Cost Savings** – Electricity North West<sup>120</sup> indicate initial findings from their DR customer research of the ‘expectation’ of six I&C customers. Customers’ initial expectations exceeded the value of potential savings to ENW of network reinforcement.

- Demand Reduction – customer expectations ranged from £300 - £1,000/kVA (and at least one respondent had no interest).
- Fault Response – all six customers potentially interested (one would need 30 minutes notice) – with expectations ranging from £100/kVA to £500/kVA.

Imperial report for ENA<sup>121</sup> – estimated savings of avoided network costs ranging from £500m to £10 billion over twenty years – dependent on heat-pump and EV penetration. Also, an earlier report by Goran Strbac (Imperial, 2008) evaluated benefits of optimising existing networks and generation and of reducing constraint costs in the networks.

---

<sup>116</sup> 5% base-case : £-9k/day - £-19/day. 10% base-case : £-12k/day - £31k/day.

<sup>117</sup> Eirgrid slides on WPDRS 2010/11. Sean Connolly and Siobhan McHugh. London. SMi conference. 19 May 2011.

<sup>118</sup> DECC. Smart Meter Roll-Out for the Domestic Sector. Impact Assessment. August 2011. Pp66-66 and p. 93

<sup>119</sup> The estimated £800m cost-saving from time-of-use from household smart meters, is in addition to the estimated benefit from expected electricity saving – valued at £4.6 bn to 2030 - based on an assumed 2.8% electricity demand reduction overall, from improved household awareness, enabled by the smart meter.

<sup>120</sup> ‘Achieving Effective Customer Engagement: the experience of Electricity North West’. Presentation by Tony McEntee. ENW. 25 May 2011. [www.customerledrevolution.com](http://www.customerledrevolution.com) website.

<sup>121</sup> Benefits of Advanced Smart Metering for Demand Response based control of Distribution Networks. ENA, Imperial College and SEDG. April 2010.

**Conclusion – Demand-Side Value in Providing System Flexibility and Avoided Peak Load**

**As this project proceeds, we would expect to develop a greater understanding of the likely near-term values available to GB electricity demand in providing (1) flexibility to the overall electricity system and (2) peak- avoidance – both in terms of providing potential peak-avoidance to the networks, including locationally - and providing ‘reliable capacity’ into the proposed GB capacity / and or wholesale market.**

## 12. What is Assumed Today about Flexible GB Electricity Demand in 2020?

**Future papers for this project will examine in detail the likely role and importance of new and flexible electrical load on the GB electricity system in the 2020's.**

Inputs to that work will draw upon the forthcoming government draft 4<sup>th</sup> Carbon Budget and the DECC / Ofgem Smart Grids scenario analysis (expected early 2012), along-side the demand-side model being developed by Brattle Group for this GB Electricity Demand project.

Given the centrality of flexible electrical load in how the electricity system may evolve in the future, this section simply gives a very brief indication of some key assumptions made today about how flexible and / or despatchable electrical load may develop to 2020.

**To 2020** - National Grid expect peak demand to be broadly similar to today, taking account of economic growth and growth from new demand – including heat-pumps and EVs – with offsets from energy efficiency and embedded generation.

**Post-2020** – National Grid expect demand profiles to flatten supported by smart meters and ToU tariffs.

By 2020, against a total expected operating reserve of 7.3 GW, National Grid suggest that there could be a total 2 GW of demand response at peak — potentially providing around one-quarter of their total Operating Reserve services. NG estimate this on the following basis<sup>122</sup>.

### **I&C 2020 Potential - Despatchable / Deferrable Load**

- **Air Conditioning** – 2.8 GW total load. If 30% captured – **would give 840 MW.**
- **Industrial Refrigeration** – 2.6 GW total load. If 10% captured (given food-safety concerns etc.) – **would give 260 MW.**

National Grid assume total I&C Despatchable / Deferrable Load therefore - 5.4 GW (i.e. around one-half of all the despatchable load they identified) – **of which, they estimate 1100 MW may be captured.**

### **Household 2020 Potential – Despatchable / Deferrable Load**

- **Domestic Wet Appliances** – 2 GW total load.
- **Domestic Refrigeration** – 1.8 GW total load including freezers. May be successful for short duration services such as frequency response – but – need relevant equipment fitted to new fridges for dynamic demand / frequency response services. A fridge would need to ‘communicate’ where in was in its cooling cycle – and therefore for any individual fridge

---

<sup>122</sup> National Grid. Operating the Electricity Transmission Networks in 2020. June 2011 Update. P.20 paras 5.2 – 5.4 & p.87 Fig 39

or freezer, questions would arise as to how often, and / or for how long, the service could be provided<sup>123</sup>.

Of the total 4 GW assumed for despatchable / deferrable household load from household wet appliances and refrigeration in the National Grid estimates - at a 5% capture-rate via tariffs and incentives – household load in 2020 is assumed **to give an estimated 200 MW of household demand response.**

### **New Sources of Despatchable / Deferrable Load: 2020 Potential?**

There are a great many different assumptions about possible penetration rates for new sources of despatchable or deferrable GB electricity load in the future, including up-take levels implicit in the incentive arrangements for Feed-In-Tariffs and the Renewable Heat Incentive. There are also assumptions in the DECC Scenarios for the 2050 Pathways Analysis, and in Committee on Climate Change Third and Fourth Budgets. Manufacturers and energy companies also have their own estimates. The DECC / Ofgem Smart Grids Forum propose to publish potential electrification scenarios, in early 2012. The forthcoming government draft 4<sup>th</sup> Carbon Budget will also incorporate assumptions on take-up of new low-carbon technologies such as electric vehicles, heat and solar PV.

As a start-point, to aid discussion, this working paper takes the assumptions recently made by National Grid in its consultation on development of Operating Reserve services in 2020<sup>124</sup>.

National Grid note that the full impact of Heat Pumps and Electric Vehicles are not well-understood in respect of how demand patterns may develop, but note that post-2020, they are both likely to have a significant impact on demand in the Distribution Networks. LCNF trials should help to improve understanding.

---

<sup>123</sup> National Grid. Operating the Electricity Transmission Networks in 2020. June 2011. Update. P.99 plus Indesit Presentation. Alessandra Suardi. SMi Conference. London. 19 May 2011. Indesit/RWEnpower CERT Trial.

<sup>124</sup> National Grid. Operating the Electricity Transmission Networks in 2020. June 2011. Update

- **Heat Pumps<sup>125</sup>** – In their initial 2009 Consultation, National Grid identified an indicative national heat-pump demand of 1.7 GW, based on an assumption of installing HPs / electric heat in 10% of the 4 million off- gas-grid homes (i.e. 400,000 dwellings - 1.5% of GB dwellings). National Grid has since updated this earlier estimate to align with the ‘low’ scenario of the DECC 2050 Pathways document. NG now assume a further 3.1 GW of Heat Pump load – **so assume a total national heat-pump demand of ~4.5 GW by 2020<sup>126</sup>**.
- In contrast to gas boilers, an efficient heat-pump operating regime is likely to involve relatively constant operation<sup>127</sup>. Assumptions therefore vary about likely heat pump flexibility at peak, unless they also have thermal storage.
- National Grid assumes that if half of HP demand can move from peak (i.e. 16.00h – 20.00h) **this could offer scope for a potential winter peak-shift of around 566 MW – around one-half of the estimated evening-peak heat-pump load.**

National Grid – Estimated Potential Demand from Heat Pumps in 2020 by Time of Day Blocks (EFA Periods - Electricity Forward Agreement).						
EFA Period	1. 00.00h – 04.00h	2. 04.00h – 08.00h	3 08.00h – 12.00h	4 12.00h – 16.00h	5 16.00h – 20.00h	6 20.00h – 00.00h
HP Cycling Regime (Percent)	6%	17%	20%	15%	25%	17%
Potential Demand (MW)	257MW	772MW	875MW	669MW	1,133MW	772MW
Assumptions - ~ 1 million homes with an average 3.5 kW load. Usage pattern similar to gas boiler regimes – and no extensive uptake of ToU tariffs with heat pumps. Aggregated demand weighted profile applied (as per ENA fig 3.1). Assume an average of 3.5 kW will meet the peak requirement of an average home. HP CoP of 3 to meet a peak heating demand of between 8kW and 12 kW – so assumes high insulation levels (may not be true for older homes, which could lead to a higher input).						

**Table 13 Estimated potential demand from heat pumps in 2020 by time of day blocks.**

- **Electric Vehicles** – 1.8 GW of potential demand from an estimated 1.1 million EVs by 2020 - **of which 100 MW assumed to be flexible / despatchable / deferrable with a**

<sup>125</sup> National Grid - p 92 . Table 13 - on HP cycling regimes.

<sup>126</sup> Updated assumption – ~ 1 million homes – i.e 10% of off-gas grid homes - 400,000 - plus 4% of remaining housing stock – 600,000.

<sup>127</sup> AECB paper. ‘Air Source Heat Pumps – Friend or Foe. A review of current technology and its viability’. John Cantor. July 2011. [www.aecb.net](http://www.aecb.net).

See also : Heat in Homes: customer choice on fuel and technologies. Energy Policy Group. University of Exeter. Richard Hoggett, Judith Ward and Catherine Mitchell. Study for Scotia Gas Networks. July 2011. Pp 38 -39.

demand profile judged more likely than heat-pumps to be compatible with being incentivised by Time-of-Use Tariffs<sup>128</sup>.

- **Distributed Generation - CHP – 7 GW ; Other - 8 GW** (PV, Energy from Waste, Biomass, Anaerobic Digestion)

**Development of Flexible Operating Reserve in 2020** - By 2020, NG will carry an additional 0.3MW operating reserve, for each additional MW of wind. NG says that it would like to develop Demand Side ‘products’ to manage predictable behaviours – with a variety of lead and delivery times. For example, ‘short-duration’ products – including fast demand-side delivery – are noted to have significant value for:

- Ramping on interconnectors
- Wind variability
- Rapid changes in demand e.g. TV pick-ups

National Grid also notes that its reserve requirements may become more *locational* – i.e. National Grid can foresee development of Regional reserve.

**Peak Avoidance for Suppliers and Networks in 2020** - ‘Short-duration’ and ‘fast’ demand-side products may offer less direct economic value to suppliers and / or networks. Their interest is perhaps more likely to be in peak-avoidance in support of lower commodity and avoided capital costs (generation, and networks potentially).

**PV Panels** – NG note that one possible ‘value proposition’ for PV – would be for it to develop in combination with storage to enable self-balancing – which may also create competition in Demand Response – i.e. to store excess power at system low-cost periods – and to export power at higher-price (peak) periods. In practice, the current flat-rate tariff structure of the <5MW FIT acts as a disincentive for this to develop for the time being.

## **Conclusion on Demand-Side Contribution in 2020 to System Flexibility and ‘Peak Avoidance’**

**The topics outlined in the sections above will be addressed in detail in the forthcoming Papers 2, 3 and 4 to be produced for the Smart Demand Forum in the year ahead.**

---

<sup>128</sup> National Grid. Operating the Electricity Transmission Networks in 2020. pp 93-94. National Grid include a ‘flexibility’ calculation for EVs as they do for Heat Pumps (above), based on EFA periods. They assume 225,000 hybrids & 825,000 EVs in 2020 . Their estimate of 100 MW of flexible EV load in 2020 is based on an assumed average 2-hour vehicle-charge in the EFA period following return home, and a total maximum demand from vehicle charging of 708 MW. They do not assume major EV charging over-night – because they assume only limited time-of-use charging in 2020 to incentivise over-night charging.

## Annex

### Glossary

**Climate Change Levy (CCL)** came into effect on 1st April 2001 and applies to energy used in the non-domestic sector (industry, commerce, and the public sector). The levy does not apply to fuels used by the domestic or transport sector, or fuels used for the production of other forms of energy (e.g. electricity generation).

**Climate Change Agreement (CCA)**. In order to protect the competitiveness of energy intensive sectors subject to international competition, Climate Change Agreements (CCAs) were introduced alongside the Climate Change Levy. CCAs provide a 65% discount on the levy if targets are agreed and met for improving energy efficiency or reducing greenhouse gas emissions.

**CRC Energy Efficiency Scheme (formerly the Carbon Reduction Scheme)**. Applies to the service sector, public sector and other less energy-intensive industries – i.e. for organisations not included in the EU ETS. The CRC EEM covers all organisations whose electricity consumption through half hourly meters is greater than 6,000MWh/yr – equivalent to an annual electricity bill of around £500k. All energy other than transport fuels will be covered, such as electricity, gas, fuel and oil. The scheme features an annual league table that ranks participants on energy efficiency performance, as reputational driver. The scheme encourages organisations to develop energy management strategies that promote a better understanding of energy usage.

**Demand response (sometimes called demand side response)** - changes in electricity usage by end-use customers from their normal consumption patterns, in response to changes in the price of electricity, or to incentive payments. Designed (1) to induce lower electricity use at peak periods or to encourage use in off-peak periods and / or (2) to provide flexibility at any time of the day in support of cost-efficient balancing of the electricity system overall. (In the future, for example, demand response could aim to increase customer use at periods of high wind output and to decrease customer use at periods of low wind output). Both (1) lower use at peak periods and (2) general demand-side flexibility may help reduce wholesale costs (short and long run), and / or reduce network reinforcement costs, and support overall electricity system reliability.

**Demand reduction (or overall load reduction or Overall Electricity saving)** - an actual reduction in the overall electricity used, not just a shifting from peak periods.

**Demand Side Management:** The planning, implementation, and monitoring of activities designed to encourage consumers to modify patterns of electricity usage, including the timing and level of electricity demand. Demand-Side Management includes **demand response and demand reduction**.

**Distributed generation** also known as embedded generation. An electricity generating plant (e.g. power station, wind turbine, CHP) connected to a distribution network rather than a transmission network.

**Energy conservation or energy saving:** Using less energy (kWh) irrespective of whether the benefits increase, decrease or stay the same.

**Energy Efficiency:** two main definitions: (1) Using less energy (kWh) to achieve the same benefits (e.g. internal temperature, industrial output etc.), (2) Using the same or a lesser amount of energy (kWh) but achieving more benefits (e.g. a warmer home, higher output).

**Firm response** – the value of demand response in terms of balancing system operation, reducing power purchase costs (short or long term) or deferring or avoiding network investment, will depend upon how “firm” that response is. Responses that rely on customer action (e.g. in response to price signals) can offer varying degrees of firmness. A completely firm response is one that is guaranteed to happen – usually through automatic control. Firm response may be achieved by having enough customers involved so that only a proportion of them need to respond to provide the desired level of response.

**Load** - the amount of electricity demand at any one time

**Peak load** – the amount of electricity demand at the times of highest demand

**Off-peak load** – the amount of electricity demand at the times of lowest demand

**Load management** - actions taken to impact upon the amount of electricity demand at any one time – i.e. to reduce or increase it. Typically through price incentives (tariffs) or direct load control.

**Peak Load Reduction** a reduction in the electricity used during peak or critical peak periods. This may either be a shifting of usage to other time periods, or may be an absolute saving.

**Flexibility of demand** - how easily electricity demand can be time-shifted (or avoided altogether) by consumers. Flexibility is thus about **consumer willingness** to shift or reduce load in response to a price signal or being willing to sign up to some other method (e.g. automatic load control). Flexibility will vary from consumer to consumer at different times of day and in response to differing levels of incentive.

**Flexibility of supply** – how easily and quickly a supply side option (power station, wind turbine, microgeneration) can respond to changes in demand. This is a function both of technical and cost factors.

**Direct Load Control:** Usually in return for a financial incentive, customers agree to have their end-uses such as air conditioners, refrigeration and water heaters controlled by the electricity retailer or network via switches or programmable communicating thermostats.

**Aggregators:** Aggregators combine the load reductions of smaller participants and sell these reductions to other market actors who wish to buy them to achieve **demand response** (e.g., networks, system operators, retailers, capacity auction managers).

**Microgeneration:** the production of heat or electricity by individual households and small businesses.

**Electricity Distribution Network** - the low voltage electricity wires carrying electricity from the transmission systems, and some generators that are connected to the distribution networks, to industrial, commercial and domestic users.

**Electricity transmission networks** - the high voltage electricity wires carrying electricity from generators to the electricity distribution networks.

**Smart meters.** Smart meters measure electronically how much energy is used, and can communicate this information to another device. So a smart-meter system comprises an electronic meter and a communications link (GSM, power line carrier or some form of radio in most cases). Two-way communications are the standard with most smart meters – they can send and receive information to and from the electricity or gas company or data manager. Typically smart meters will be designed to measure consumption at many intervals (e.g. half hourly) and thus can facilitate a range of tariffs. They can also be linked to a display device to provide consumption and cost information to consumers.

**Smart grids.** A smart grid is part of an electricity power system which can intelligently integrate the actions of all users connected to it - generators, consumers and those that do both - in order to efficiently deliver sustainable, economic and secure electricity supplies.

## DATA ANNEXES

### Annex 1 - Regional Electricity Consumption Data<sup>129</sup>

Major data-sets are available, broken down by half-hourly<sup>130</sup> and non-half hourly meter customers, showing how much GB electricity was consumed by:

- **GB Government Office Region**
- **Local Authority area**

Annualised data for every GB MPAN (meter point administration number) is derived from actual meter-reads (~80%) and from ~20% estimated reads, and aggregated by post-code. Data and maps giving a breakdown of electricity demand by Local Authority area are available on DECC's website.

Key insights from this 2009 data include:

#### Regional Domestic Consumption Analysis - 2009

- **Average domestic consumption per meter – 4,152 kWh** (North-east - lowest 3,572 kWh. South-east highest - 4,477 kWh). The south-east consumed 15% of household electricity in 2009 and the north-east 4%.
- **Average standard consumption** (i.e. non-Economy 7) – **3,779 kWh**
- **Average Economy-7 consumption – 5,715 kWh** (Wales highest – 7,248 kWh. East Midlands lowest – 4,766 kWh).
- **73% of GB household consumption in 2009 was attributed to standard domestic meters and 27% to Economy 7.** Unsurprisingly, this split varies by region: for example, in the North-East - 88% Standard & 12% Economy 7. In the East-Midlands, the split is 50:50.
- **Average domestic electricity consumption per meter reduced by 10 % between 2005 and 2009.**

#### Regional Non-Domestic Electricity Consumption Analysis – 2009.

(I.e. I&C customers - data from both half-hourly and non-half hourly meters).

- **High average consumptions per meter may reflect those areas with a comparatively few but very large customers** e.g. Ellesmere Port & Neston – 334 MWh (North West) ; City of London – 330 MWh ; Neath Port Talbot – 267 MWh
- **Low average consumptions per meter may reflect high overall volumes of electricity consumed in an area – but with a large number of non-domestic users.** E.g. Westminster, Manchester, Birmingham.
- **Lowest consumption per meter** – Isles of Scilly – 18 MWh; Orkney – 23 MWh.

<sup>129</sup> DECC – DUKES plus article in Energy Trends. December 2010. 'Sub-national electricity consumption statistics for 2009'. Pp. 26-39

<sup>130</sup> Excludes largest transmission-connected I&C HH customers

- **2005 – 2009:** Greater London excepted, all regions saw a decrease in average non-domestic consumption between 2005 – 2009 – from 8.8MWh in the North West, to 1.5 MWh in the south-east.

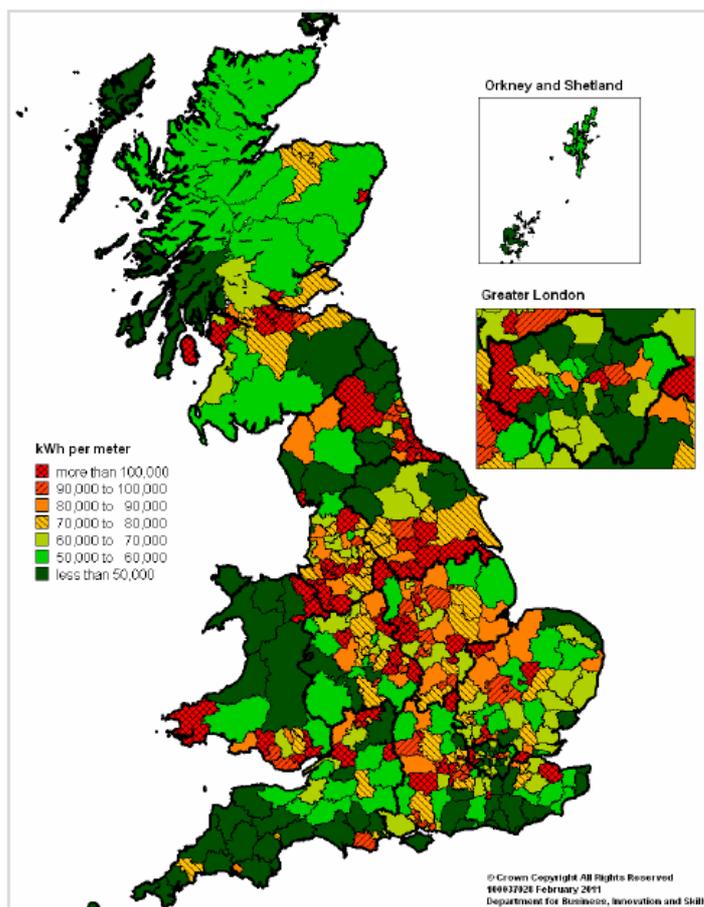
### Balance of Domestic to Non-Domestic Consumption – 2009

- The balance of domestic and non-domestic electricity consumed varies by region by a range of 10%. E.g. London – 33% Domestic, 67 % Non-Domestic.  
South West – 43% Domestic, 57 % Non-Domestic

**This sub-national data offers helpful insight into electricity-use across the country, and in turn could better inform targeted actions and measures<sup>131</sup>.**

**Figure 12 Average industrial/commercial electricity consumption per meter point in 2009 (KWh)**

**Map 2: Average industrial/commercial electricity consumption per meter point in 2009 (kWh)**



<sup>131</sup> DECC also produces equivalent regional data for gas.

## Annex 2 - Estimated Electricity End-Use by Economic Sector<sup>132</sup>

**Electricity** - estimated electricity end-use across key economic sectors, as a percentage of all energy-use (excluding transport) is as follows for 2008:

- **Heat-use of electricity** (space-heating, hot water, cooking/catering) **as a percentage of all energy consumption** (excluding transport): Domestic sector – 8%; Services – 15%; Industry – 17%.
- **Non-heat-use of electricity as a percentage of all energy consumption** (excluding transport): Households - 16%; Services – 33%; Industry – 21%.

**Of electricity supplied in 2008, the percentage estimated to be for heat (i.e. space-heating, hot-water, cooking/catering, industrial processes)** in key economic sectors was as follows:

- **Households – 33% heat** (of which, a large proportion is likely to be Economy 7 units - reflecting that ~20% of all household electricity supplied is off-peak) ;
- **Services – 31 % heat ;**
- **Industry – 44% heat**

The following three tables attempt a more detailed break-down of estimated electricity end-use by key economic sector.

<b>Domestic Sector -Estimated UK Electricity Consumption by end-use –2008</b>		
Domestic End-Use	Electricity (thousand tonnes of oil equivalent)	% age
Space Heating	1,455	13%
Water Heating	1,501	14%
Cooking / catering	625	6%
<b>Heat total</b>	<b>3,582</b>	<b>33%</b>
Lighting and Appliances	7,236	67%
<b>Overall total</b> (excl. Renewable Heat)	<b>10,818</b>	100%

Source Energy Trends September 2010. 'Estimates of heat-use in the UK'.

**Table 14 Estimated UK domestic electricity consumption by end-use 2008**

<sup>132</sup> DECC - Energy Trends. September 2010. 'Estimates of Heat Use in the United Kingdom'. Pp35-40.

<b>Services Sector -Estimated UK Electricity Consumption by end-use - 2008</b>		
<b>Estimated End Use</b>	<b>Electricity (thousand tonnes of oil equivalent)</b>	<b>Percentage</b>
Space Heating	1,145	14%
Water Heating	287	3.5%
Cooking / catering	1,070	13%
<b>Heat total</b>	<b>2,502</b>	<b>31%</b>
Computing	499	6%
Cooling & Ventilation	703	9%
Lighting	3,292	40%
Other uses	1,052	13%
Overall total (excl. Renewable Heat)	8,049	98%
Source Energy Trends September 2010. 'Estimates of heat-use in the UK'. Services includes: Commercial, Education, Government, Retail, Warehouses, Hotels, Catering – but not agriculture.		

**Table 15 Estimated UK services sector electricity consumption by end-use – 2008**

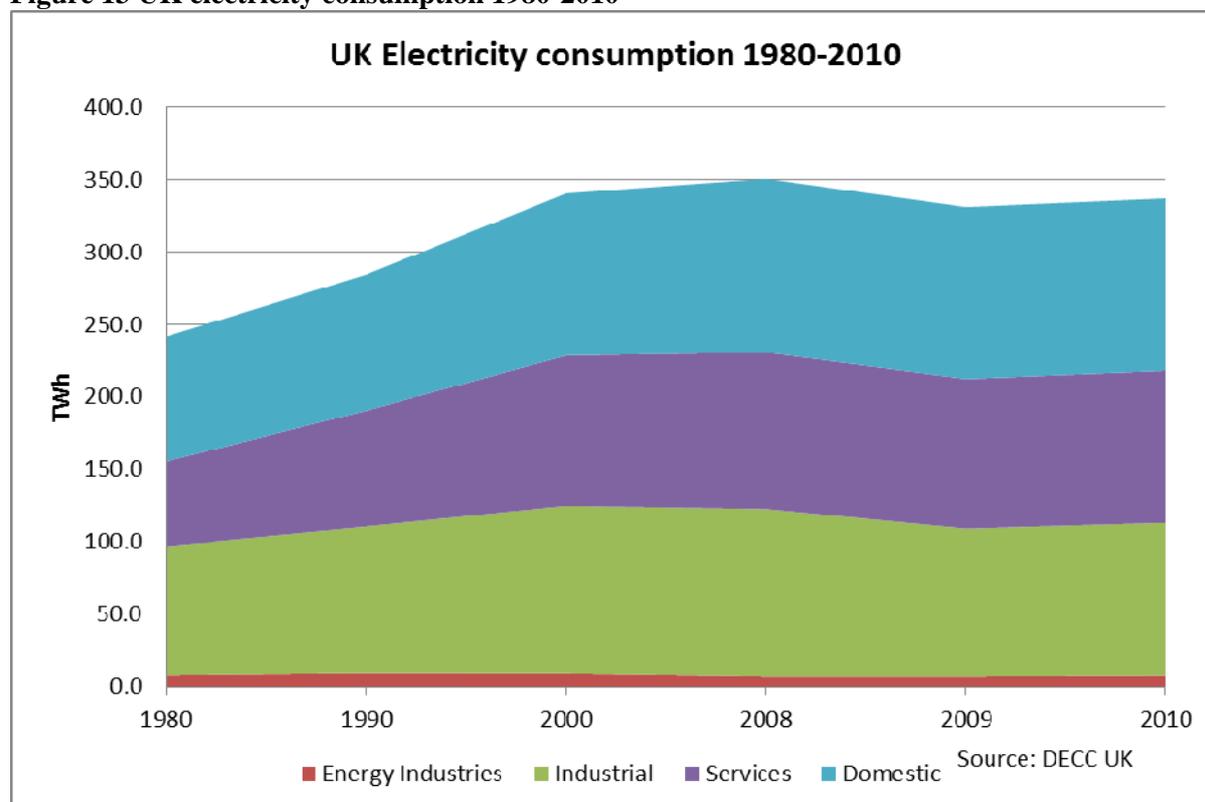
<b>Industry Sector -Estimated UK Electricity Consumption by end-use - 2008</b>		
<b>End Use</b>	<b>Electricity - (thousand tonnes of oil equivalent)</b>	<b>Percentage</b>
Space Heating	730	8%
High Temperature Process	1,226	13%
Low Temperature Process	1,570	17%
Drying / Separation	572	6%
<b>Heat Total</b>	<b>4,099</b>	<b>44%</b>
Motors	3,030	33%
Compressed Air	864	9%
Lighting	272	3%
Refrigeration	518	5%
Other	469	5%
Overall total (excl. Renewable Heat)	9,251	99%
Source Energy Trends September 2010. 'Estimates of heat-use in the UK'. See p37 for detailed list of industry sub-sectors (assume they equate to CCL groups?)		
Excludes mining of metal ores, electricity & gas manufacture & distribution, construction and unclassified. Total does not include heat sold, blast furnace gas, coke oven, gas or non-electricity renewables and waste.		

**Table 16 Estimated industrial electricity consumption by end-use - 2008**

### Annex 3 - Historic Trends in Electricity Consumption by Economic Sector<sup>133</sup>

UK electricity supply grew at an average annual rate of 1.5% from 1970 through to 2009. In the 1970's, demand grew between 2 - 2.5% pa, declining in the early 1980s to 1% pa but returning to 2% pa growth by the late 1980's. In the 1990's electricity supply grew at 1.5% pa, then at 1% pa from 2000 to 2005, declining between 2005 and 2009 by 1.5% in total. Growth reflected economic conditions, but also, in recent years electricity demand growth has been impacted by effective measures to improve end-use and appliance efficiency<sup>134</sup>.

**Figure 13 UK electricity consumption 1980-2010**



<sup>133</sup> DECC – DUKES. Long Term Trends Section. Chapter 1 Energy. July 2010 & 2011 (Table 1.1.7) Chapter 5. Electricity. June 2010 pp200-202 & DECC - UK Energy in Brief 2011.p.31.

<sup>134</sup> UK has seen long-run falling energy ratios since 1970– that is, the degree to which economic growth and energy-use are linked. For electricity, reasons for higher electricity intensities include : improvements in energy efficiency; saturation in ownership of main appliances; decoupling of certain uses eg I&C space-heating, to long-run output growth; and a structural shift from energy-intensive activities (eg steel) to services. [DECC. DUKES. Long Run Trends. Chapter 1. Energy. P.158. July 2010].

Table 9 below shows recent trends in electricity demand growth by sector. In any one year winter temperatures influence overall electricity consumption. 2007 was cool; 2008 was colder – with the average temperature across the year lowest since 1996. Average for 2009 was similar to 2008, but with a colder Q1. 2010 was the coldest year in GB since 1987 (1 degree Celsius lower than 2009) – and included the coldest December for 100 years.

<b>UK Electricity Consumption – 1980-2010</b>						
TWh	<b>1980</b>	<b>1990</b>	<b>2000</b>	<b>2008</b>	<b>2009</b>	<b>2010</b>
<b>Energy Industries</b>	8.5	10	9.7	7.7	7.7	8.2
<b>Industrial</b>	88.6	100.6	115.3	115.1	101.4	104.9
<b>Services</b>	58.4	80	103.5	107.9	103.3	105.1
<b>Domestic</b>	86.1	93.8	111.8	119.8	118.5	118.7
<b>Total</b>	241.6	284.4	340.3	350.4	330.5	336.9

Source – UK Energy in Brief. 2011. DECC. P.31

**Table 17 UK Electricity consumption- 1980-2010**

**Industrial Electricity Consumption** – Notwithstanding growth of the Services sector, industrial electricity consumption has accounted for around one-third of UK demand since the 1970's. In the thirty years to 2005, there was a 60% increase in industrial electricity consumption. In 2006, industrial electricity consumption fell for the first time in 5 years - by almost 1% compared to 2005, and it has continued to fall, with consumption in 2009 15% below a 2005 high-point. Increased efficiency and improved electricity intensities contributed to the fall on 2008, but the economic downturn is also significant. Industrial electricity consumption fell 11.8% in 2009 - to its lowest level since 1994 – but in 2010 rose by 3.5% due to improving economic conditions but was still 8.8% below 2008 levels<sup>135</sup>. Iron & Steel dropped 23%. In 2009, 11% of industrial demand was met by auto-generation.

**Services Electricity Consumption** - includes commercial and public sectors, transport and agriculture. The Services sector has seen the biggest growth UK in electricity consumption, growing by 75% in the twenty years from 1980 from 25% of all demand to 31% in 2009. Growth slowed slightly between 2004 to 2008. In 2009, Service sector demand fell 4.5% on 2008, back to the lowest level since 1999. Services consumption rose by ~2% overall in 2010, as the economic climate improved, and temperatures fell in the final quarter. Improved electricity efficiency is offset by greater use of lighting, heating and cooling – including, for example, in data-centres.

**Domestic Electricity Consumption** – In the past thirty years, the volume of electricity consumed in the domestic sector has increased by 42%. In 1970, domestic sector consumption was 40%, reduced to one-third in the 1980's, and remained at one-third until 2005, when it increased slightly at the expense of industrial consumption. In 2009, domestic electricity demand was ~37%. From 2000 to 2005, household electricity use grew by 4.5% to

<sup>135</sup> DECC. DUKES. July 2011. Long-Term Trends. Electricity. Chapter 5. p.206

reach a high of 116.8 TWh. Consumption fell in 2006 and 2007 due to mild winter weather, energy efficiency and higher prices. In 2008, a cold winter led domestic consumption to rise by 2.5 % - but to fall again in 2009 to 118TWh. In 2010, it rose very slightly, most likely due to a very cold final quarter.

## Annex 4 - Heat and Non-Heat Uses of Electricity and Other Fuels

**Heat** - Of total final UK energy-use in 2008, 47% of energy consumed was estimated to be for heat purposes – amounting to 77 % of final total UK energy-use (excluding transport).

As a percentage of energy end-use by all fuels, gas-supply for heat in 2008 (space-heating, hot water, cooking/catering, process heat) was estimated to be: Households – 68%; Services – 46%; Industry – 43%.

The chart below sets out the relative shares of gas and electricity across economic sectors in estimated UK heat-delivery (i.e. space-heating, hot-water, and process heat).

Electricity notably prevails in non-heat uses.

<b>Estimated UK Gas and Electricity Consumption by End-Use by Sector<sup>136</sup></b>						
2008 mtoe NB - Omits oil & solid fuel	<b>Space Heating</b>		<b>Water Heating</b>		<b>Non-Heat Uses – Appliances, IT, Processes etc.</b>	
	<b>Gas</b>	<b>Electricity</b>	<b>Gas</b>	<b>Electricity</b>	<b>Gas</b>	<b>Electricity</b>
<b>Households</b>	21.8	1.4	8.3	1.5	0.03	7.2
<b>Services</b>	6	1.1	1.1	0.28	0.1	13.5
<b>I&amp;C</b>	1.3	0.7	-	-	1.4	9.1
<b>I&amp;C Process Heat</b>	9.8	3.2	-	-	-	-

Source - Derived from DECC Energy Trends. September 2010. 'Estimates of Heat Use in the United Kingdom'. Tables 2, 3 & 4 on UK energy consumption by fuel and end-use.

**Table 18 Estimated UK Gas and electricity consumption by end-use by sector 2008**

<sup>136</sup> Source - Derived from DECC Energy Trends. September 2010. 'Estimates of Heat Use in the United Kingdom'. Tables 2, 3 & 4 on UK energy consumption by fuel and end-use. 2008.

**Estimated Sector End-Use by All Fuels**

<b>Estimated UK Domestic Energy Consumption by Fuel (thousand tonnes of oil equivalent)- 2008</b>						
End Use	Gas	Oil	Solid Fuel	Electricity	Total	
Space Heating	21,887	2,305	596	1,455	26,244	
Water Heating	8,357	725	155	1,501	10,738	
Cooking / catering	668	3	3	625	1,300	
<b>Heat total</b>	<b>30,9123</b>	<b>3,033</b>	<b>753</b>	<b>3,582</b>	<b>38,282</b>	
Lighting and Appliances	3	-	-	7,236	7,239	
Overall total (excl. Renewable Heat)	30,916	3,033	753	10,818	45,521	
Source Energy Trends September 2010. 'Estimates of heat-use in the UK'.						

**Table 19 Estimated UK domestic energy consumption by fuel - 2008**

**Domestic Sector** - In 2008, gas-use was 81% of household consumption for heat-purposes – and 68% of overall domestic consumption.

<b>Estimated UK Service Sector Energy Consumption by Fuel (thousand tonnes of oil equivalent)- 2008</b>						
End Use	Gas	Oil	Solid Fuel	Electricity	Total	
Space Heating	6,056	974	15	1,145	8,191	
Water Heating	1,175	92	3	287	1,558	
Cooking / catering	652	39	-	1,070	1,761	
<b>Heat total</b>	<b>7,884</b>	<b>1,105</b>	<b>17</b>	<b>2,502</b>	<b>11,509</b>	
Computing	-	-	-	499	499	
Cooling & Ventilation	24	-	-	703	728	
Lighting	-	-	-	3,292	3,292	
Other uses	129	11	-	1,052	1,192	
Overall total (excl. Renewable Heat)	8,037	1,116	17	8,049	17,220	
Source Energy Trends September 2010. 'Estimates of heat-use in the UK'. Excludes Agric. Total excludes heat sold and renewable fuels (i.e. for renewable heat).						

**Table 20 Estimated UK service sector energy consumption by fuel – 2008**

**Services Sector** - In 2008, gas was the fuel primarily used in the services sector. Gas delivered 69% of total heat use and 46% of overall consumption. Electricity for heat comprised 31% of all electricity consumption by the sector and 22% of energy consumption for heating purposes.

56% of energy used for space-heating was consumed by Education, Government, Retail and Warehouses. For all services sub-sectors, except communication and transport, the majority of energy was used for heating purposes. Generally, space-heating accounted for the greater part of energy used for heating purposes (44-87%) – with the exception of the hotel and catering sub-sector, where 56% of consumption for heat was made up by catering and hot-water.

<b>Estimated Industrial Energy Consumption by Fuel (thousand tonnes of oil equivalent)- 2008</b>						
End Use	Gas	Oil	Solid Fuel	Electricity	Total	
Space Heating	1,314	557	95	730	2,695	
High Temperature Process	2,490	311	1,120	1,226	5,147	
Low Temperature Process	4,643	1,541	236	1,570	7,990	
Drying / Separation	1,860	611	148	572	3,191	
<b>Heat Total</b>	<b>10,307</b>	<b>3,019</b>	<b>1,598</b>	<b>4,099</b>	<b>19,023</b>	
Motors	-	-	-	3,030	3,030	
Compressed Air	-	-	-	864	864	
Lighting	-	-	-	272	272	
Refrigeration	-	-	-	518	518	
Other	1,404	421	175	469	2,469	
Overall total (excl. Renewable Heat)	11,711	3,440	1,773	9,251	26,176	
<p>Source Energy Trends September 2010. 'Estimates of heat-use in the UK'. See p37 for detailed list of industry sub-sectors (assume they equate to CCL groups?)</p> <p>Excludes mining of metal ores, electricity &amp; gas manufacture &amp; distribution, construction and unclassified. Total does not include heat sold, blast furnace gas, coke oven gas or non-electricity renewables and waste.</p>						

**Table 21 Estimated industrial energy consumption by fuel – 2008**

**Industrial Sector** – Electricity use for heat made up 22% of consumption for heat – and 44% of overall electricity consumption within the sector.

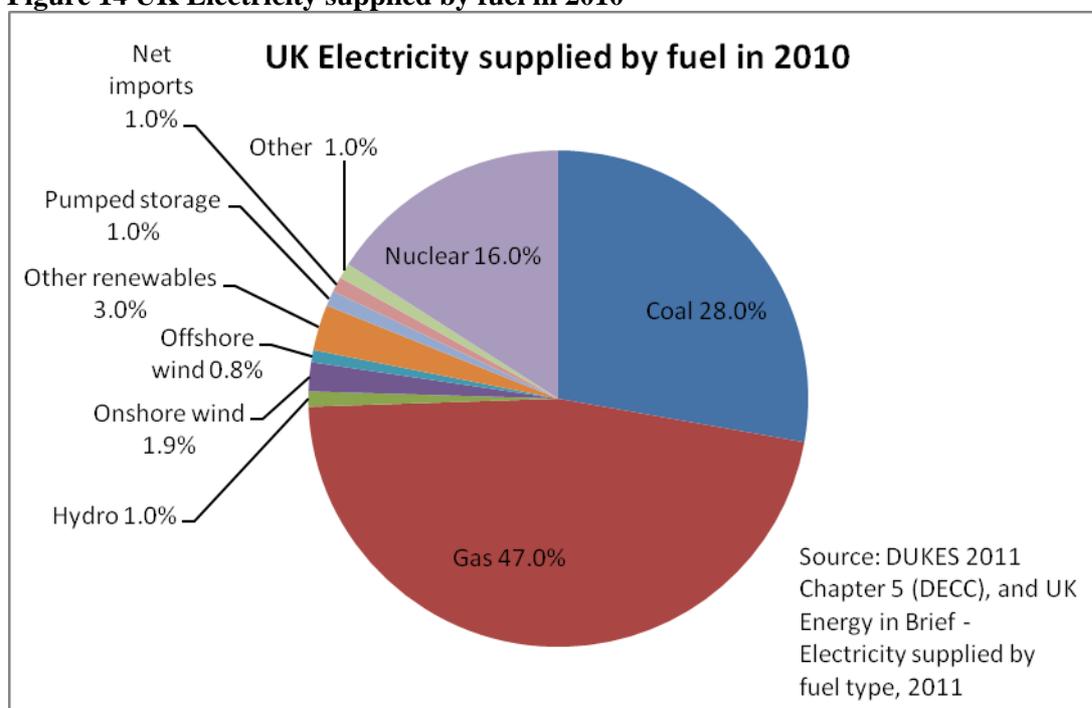
## Annex 5 - UK Electricity Capacity and Supply by Fuel

**Generating Capacity** – At the end of 2009, the UK had a fixed total of generating capacity of 85.3 GW, plus an import / export capability of 2.5 GW (2 GW France – 0.5 GW Ireland)<sup>137</sup>.

**Primary fuel used for UK electricity generation** – since 2005, the share of gas and coal as fuels for UK power generation has varied relative to nuclear availability and prices for carbon, coal and gas. In 2009, coal's generation-share (mtoe) was 32% against 39% for gas. In 2010, coal was 35% and gas 43% of generation-share<sup>138</sup>.

**Shares of electricity-supplied by fuel in 2010-** In 2010, net shares of UK electricity were supplied by different fuels as follows (total 364 TWh)).

**Figure 14 UK Electricity supplied by fuel in 2010**



<sup>137</sup> DECC Statutory Security of Supply Report. HC 452. November 2010. Pp 8- 9

<sup>138</sup> DECC - DUKES Table 5.1. June 2011

## **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 trustees are: Ted Cante (Chair); Phil Barton (Secretary); Trevor Pugh (Treasurer); John Hobson; Derek Osborn; David Sigsworth. Its projects are developed by the trustees and a number of associates and consultants.

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.

Sustainability First  
Grosvenor Gardens House  
35-37 Grosvenor Gardens  
London  
SW1W 0BS

[www.sustainabilityfirst.org.uk](http://www.sustainabilityfirst.org.uk)

Email [info@sustainabilityfirst.org.uk](mailto:info@sustainabilityfirst.org.uk)

**Sustainability *First***