Demand Side Market Participation Report

for

Department of Energy and Climate Change

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Executive Summary

Expected developments in the electricity generation sector over the next decade, including the closure of a significant volume of conventional generation and the substantial increase in wind capacity, have led the Department of Energy and Climate Change (DECC) to investigate the potential of Demand Side Management (DSM) techniques as a tool for increasing system security.

The new developments in the electricity generation sector will lead to a less predictable system, with potentially higher levels of demand if (for example) electric vehicle use expands. The possibility of tighter capacity margins, combined with the compositional changes of the electricity generation mix will present challenges in managing the system which could be met by exploiting DSM techniques for use in balancing the electricity system.

Demand Side Management involves the reduction of customer demand, mainly due to a price incentive or some form of automatic response to a signal. Customers can decrease their demand by using "back-up" generation, by delaying their electricity consumption or by foregoing it completely. Such "discretionary" load is often but not exclusively associated with heating and air-conditioning demand.

This report outlines the existing DSM schemes, which have helped to maintain system security, and looks at how they could be expanded and explores new schemes, some of which could be facilitated by the proposed Smart Metering arrangements. The applicability of DSM schemes to future system management challenges is examined. We considered a selection of measures to assess their effectiveness in more depth:

- *Ti e of Use TOU tariffs* – With TOU Tariffs, customers are charged different prices according to when they consume electricity. The tariffs can vary between simple two-rate schemes such as 'Economy 7' (a UK tariff which is popular with domestic customers) to complex multi-rate tariffs for commercial and industrial customers. The proposed Smart Metering arrangements could facilitate a wider adoption and increased sophistication of TOU tariffs;
- *Maxi u De and Sche es* – Maximum Demand schemes range from simple tariffs which apply charges based upon customers maximum demand to schemes which limit customers demand at times of tight supply-demand balance;
- *Direct Load Control* – under this technique, customers ' appliances are remotely disconnected or the consumption of the appliance reduced, for example by changing the temperature setting in a thermostat

There is clearly great uncertainty around factors such as future levels of demand growth, the commissioning of new capacity, and how suppliers and customers will respond to the future demand-supply developments and the opportunities presented by developments in metering. Analysis of DSM will always be qualified, in the absence of detailed information relating to how individual customers use electricity at different times of the day and year.

The schemes discussed in this report could increase the achieved volume of DSM and can address, albeit partly, some future challenges. The proposed Smart Metering arrangements could facilitate the increase of DSM that could be provided by residential and smaller commercial customers by:

- reducing the additional metering costs currently associated with TOU tariffs;
- enabling the provision of more sophisticated TOU tariffs, including the multi-rate tariffs to residential customers and the provision of more dynamic price signals to customers; and
- allowing some direct load control of selected appliances.

The key findings from the analysis of customer sales and uses of electricity are:

- The volume of discretionary load across all sectors would appear to be lower in GB than in other countries where DSM techniques are widely used (e.g. USA, southern Europe), since GB has:
  - less extreme weather, and therefore less air-conditioning load, than these countries; and
  - a high use of natural gas to provide heating, and less reliance on electricity to provide heating at peak times.
- The high value placed upon time, and the use of electricity – consumers are unwilling to inconvenience themselves for a small financial saving when the effort / time required is high.

Overall it is estimated that there is in total around between 9 and 17 GW of "discretionary" load in GB, which can be "time-shifted" to a different time period or foregone completely.

The report explores the benefits delivered by increased levels of DSM:

- efficiency benefits, in terms of lower fuel costs and EU ETS Emission Costs, from making better use of the existing generation fleet;
- reduced requirement for new conventional generation capacity; and
- generally increased security of supply.

Overall it is estimated that 1 GW of additional DSM will reduce the requirement for investment in conventional generation by 500 3kin0179 0 Td (t)Tj r

1 Introduction – reasons for study

Expected developments in the electricity generation sector over the next decade only increase the scope for Demand Side Management (DSM) in helping to provide flexibility and in maintaining electricity Security of Supply. These include:

- Closure of electricity generation: even though new capacity is under construction, there is the possibility of delays in completing some of the projects. This, combined with the fact that a significant proportion of current electricity generation is expected to close over the next decade (driven by LCPD and scheduled closures for nuclear), could result in the reduction of the margin of spare capacity;
- EU 2020 Renewables Target (RES): to meet these targets, it will be necessary to increase significantly the amount of renewable electricity generation capacity, mainly comprised of wind generation, which provides intermittent supply of electricity.
- Electric Vehicles and Heat: the popularization of electric vehicles and the use of electricity heat could change the typical load profile, increasing the level of demand for electricity and affecting seasonal and daily peak loads.

As a result, the future electricity system could look rather different to today's system requiring different techniques for balancing supply and demand at all times. For instance, the developments highlighted above could lead to a less predictable system, with potentially higher levels and different profiles/shapes of demand. In this context demand side response/management techniques could be a useful tool in balancing the electricity system.

This report is structured as follows:

- Chapter 2 briefly summarises the dynamics of the different situations when DSM techniques contribute to balancing the system and discusses National Grid's and the market's requirement for reserve services
- Chapter 3 explores the volume of discretionary electricity demand available from the different customer classes
- Chapter 4 provides a description of the current DSM schemes and possible new DSM developments
- Chapter 5 provides an assessment of the barriers and incentives of the 3 selected DSM techniques
- Chapter 6 explores the benefit of additional DSM

2 Requirements for maintaining a balanced/secure system

The demand-supply balance can be tight for a variety of reasons, which for ease of discussion can be grouped into 3 broad situations, according to when the future tightness in the system becomes apparent:

1. low year-ahead plant margin which can be caused by low levels of new construction
2. day-ahead problems caused by high rates of plant unavailability or abnormally high demand levels
3. with-in day problems caused by low levels of "on-the-day" generation or unexpectedly

These three situations have different security of supply implications, and benefit from different market responses and DSM techniques. The earlier the issue becomes apparent, the more effective traditional static DSM measures are, whilst events that occur at short notice often require more "dynamic" measures and response[1]. The following ordering of situations by the degree of "dynamic" response required is not definitive, as for example low winter plant availability could be recognised in the autumn but only require a response in December and January.

Yearahead Low plant argin issue

This is the traditional capacity shortfall issue, which is anticipated "well in advance", but not so far in advance that there is time to build new capacity. It is traditionally managed by static "yearahead" DSM measures such as Time Of Use (TOU).

Dayahead Availa ility issue

This issue could be due to a variety of reasons, ranging from random plant unavailability to exceptionally high demand levels. Increased levels of wind capacity in the future will tend to lead to an increased frequency of these events, all other things remaining the same.

ithin day Reserve issue

The important issue is the suddenness, ranging from a few hours notice to a few minutes notice, and the randomness of the occurrence. These situations are not restricted to the winter peak periods, but can and do occur randomly during the year. The traditional "static" measures, such as Economy 7 tariffs, do not encourage dynamic market response and more sophisticated measures are required.

2.1 National Grid's Role in Security of Supply

National Grid, as electricity System Operator, currently has a responsibility for ensuring there is sufficient reserve available to cover for short term generation loss and demand forecast error[2]. Short Term is considered to be around 3-4 hours before real time. After this time, it is increasingly difficult for the market to respond, as power stations may be unable to reach full output at short notice, and Gate Closure rapidly approaches, after which time National Grid is responsible for maintaining the supply-demand balance.

National Grid contracts with generators and Demand Side Providers, typically customers with back-up generation or who can reduce demand, for them to provide a reserve service

[1] "Dynamic" measures are those that can respond to short-term developments in the electricity demand-supply balance

[2] http://www.nationalgrid.com/NR/rdonlyres/012BE506-F6A1-4D16-BADD-C7A2FC49C52D/1913/NGTs_Role_in_Securing_Reserve.pdf

Figure 1: Short Term Reserve Requirement under different scenarios

Source: National Grid[6]

2.2 Market's role in Security of supply

Currently the market, rather than National Grid, has the primary responsibility for ensuring that there is sufficient generation capacity available on the day / dayahead so that at Gate Closure forecast demand can be met in full. Generators who do not produce the electricity that they have contracted to generate and suppliers whose customers have consumed more than the supplier has purchased are exposed to an Imbalance charge. This imbalance charge reflects the actual costs incurred by National Grid in balancing the system. As the costs of purchasing electricity tend to be higher when the demand-supply balance is tighter, generators are encouraged to schedule their planned outages outside of peak-priced periods, and customers are encouraged to lower their demand during peak periods. Though there are events outside of the control of generators which reduce availability, conventional thermal generators tend to have high availability when required to do so, as they do have a degree of control over the exact timing of outages and can continue to operate for a limited period of time even when there are operating "under fault".

Wind is not as predictable as conventional thermal capacity. There is not 100% accuracy with forecasting wind output, and meteorological forecasts change frequently. Increased importance will be placed on the ability of both generators and consumers to respond to a short-notice change in forecast wind output. However it should also be noted that it is difficult to extrapolate from the current experience of relatively low levels of wind output to a future situation when there could be approaching 30 GW of wind capacity, but there is a clear requirement for flexibility from generation and the demand side in order to deal with the day to day volatility of wind output.

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[6] http://www.nationalgrid.com/NR/rdonlyres/B5D714DA-EB03-4687-836D-6E5066B9C812/35051/160609_2020.pdf

3 Electricity Demand

Through an analysis of customers ' use of electricity, this chapter seeks to provide an estimate of the volume of "discretionary" load that can be demand managed.

3.1 GB System Level

Generation

Generation from large producers, as seen by National Grid, was stable between 2005/06 and 2007/08 at around 350 TWh, but fell by 4% in 2008/09 mainly due to the economic recession. Demand can fluctuate from one year to the next based upon weather conditions, and the weather-corrected outturn figures are an estimate of what demand would have been under "normal" weather conditions.

Table 1 – Headline System Figures

		2005/06	2006/07	2007/08	2008/09
Actual Peak Demand	**GW**	60.3	58.4	60.7	59.2
ACS Corrected Peak Demand[7]	**GW**	62.2	61.8	61.4	59.0
Actual Electricity Requirements	**TWh**	355.8	347.3	348.4	340.7
Weather Adjusted Electricity Requirements	**TWh**	354.4	350.5	351.0	337.6
Actual load Factor	**%**	67%	68%	66%	66%
Weather-adjusted load Factor	**%**	65%	65%	65%	65%

Source National Grid 7 Year Statement

There has been low growth in electricity demand over recent years, with average demand at around 39-40 GW, and peak demand at around 59-62 GW, have both been relatively stable. Reflecting the economic decline, demand in 2008/09 was 4% lower than in 2007/08. The system load factor is the ratio of average demand to peak demand, and this has therefore remained stable at around 65% over the recent years.

Consumer Sales

Sales to the different customer classes are roughly equal, as summarised below. Total sales were stable at around 320-330 TWh until the recession in 2008, when sales are estimated to have fallen.

Table 2 - GB Sales, TWh

	2000	2001	2002	2003	2004	2005	2006
Domestic	112	115	115	116	116	117	116
Commercial & Public	88	90	91	91	91	92	92
Industrial	102	102	102	103	103	106	105
Other	13	13	13	14	13	13	14
Total	315	320	321	324	323	328	327

Table 3 – Generation, GB TWh[8]

	2002	2003	2004	2005	2006
Major Power Producers	354	363	358	362	362
Other generators	33	36	36	36	37
Total	387	398	394	398	398
Loss Adjustment Factor	110%	112%	111%	110%	111%

Source: DECC[9],

The losses associated with the transmission and distribution of electricity are typically around 10% – each 1 MWh of demand, as measured at the customer meter, actually requires 1.1 MWh of generation.

System Load Shape

Though each customer’s load has its own characteristics, which are described in greater detail below, the total load averaged across each customer class is reasonably stable and predictable.

As expected, commercial and industrial customers have high load during daytime hours on business days, whilst residential load is highest in the morning and evening. The peak demand on the system over the whole year occurs on a cold winter weekday evening around 5 to 6pm, as the increasing residential load coincides with still strong commercial and industrial demand. There is a significant volume of over-night residential load, due to Economy 7 night storage systems, which are "teleswitched on" overnight via a radio signal.

Colder weather can lead to significant increases in demand. Demand increases by around 600 MW in the winter when the temperature falls by 1 degree C. This is due to a combination of 3 factors:

- increased demand from consumers with electric heaters;
- the electric pumps on gas central heating system working harder; and
- the behavioural response as consumers stay in–doors.

No detail of the relative importance of each factor or the sectoral split between commercial, domestic or industrial customers has been found.

Between June and August, demand increases by around 200-400 MW when the temperature rises 1 degree C at temperatures above 20 degrees C[10].

As illustrated by Figure 2, demand overnight is typically much lower than during the daytime, and the lowest demand in the year occurs on a Sunday in high summer, when there is little over-night electric storage heating demand.

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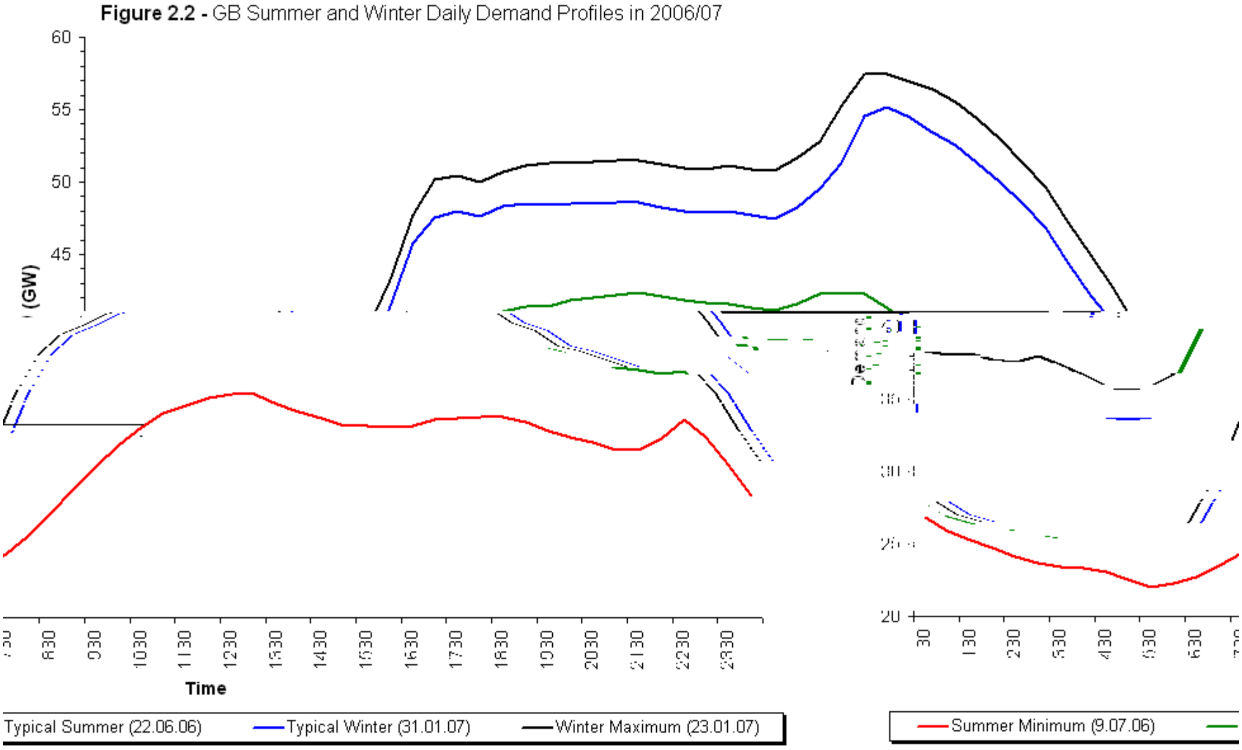
[8] Generation figures are different to NG figures due to NG only seeing a subset of all generation. DECC figures include output from small generators. Also figures are calendar year, not April to March years.

[9] http://www.decc.gov.uk/en/content/cms/statistics/publications/dukes/dukes.aspx

[10] http://www.nationalgrid.com/NR/rdonlyres/491E346E-49F4-40A1-98D0-7D0C0075E75B/33228/Summer_Outlook_Report_Final1.pdf

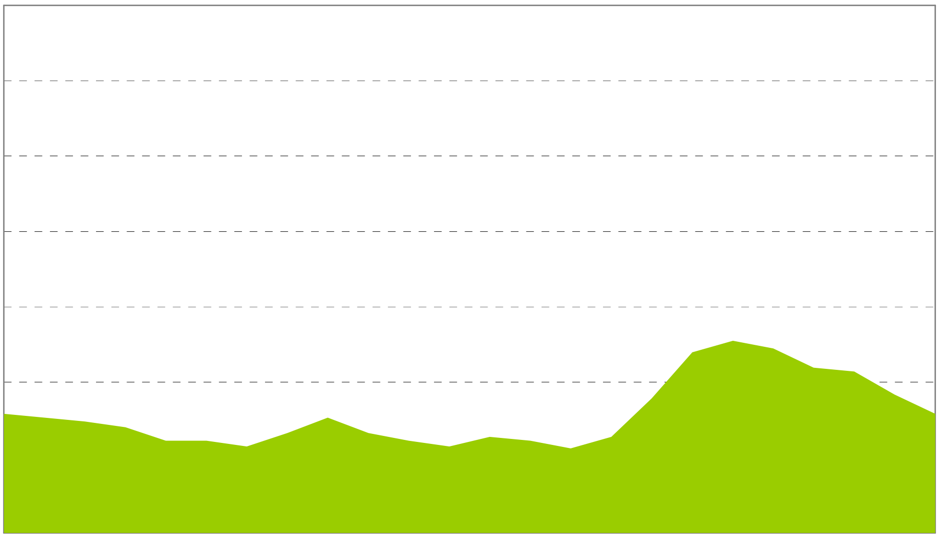
Figure 2: GB Demand Profiles



Source: National Grid 7 Year Statement

Based upon our analysis of domestic, commercial, and industrial load-shapes, we estimate the contributions to system demand in the following sections. There is limited information available on the load characteristics of the complete range GB customers, especially under different weather conditions. The representative load-shapes for the different customer classes underestimate the over-night load and the increase in demand at the peak hours of the day. This is related to the under-estimation of the additional lighting load that occurs during the winter months.

Figure 3: System Demand profile, estimated customer class contribution



Eurostat breaks down the domestic sector into 5 sub-groups, by volume of consumption, with Da being the customer class with the lowest annual consumption and class De being those customers with the highest annual consumption.

Table 5 – Sales by domestic sub-group

	Average sales per customer (MWh)	Customers million	Sales TWh
Da	0.6	7.1	4.3
Db	1.2	6.1	7.4
Dc	3.5	3.5	12.3
Dd	7.5	4.5	34.0
De	20.0	2.9	57.1

Table 8 - Proportion of each market by fuel, domestic customers

	Space heating	Water	All heating
Gas	84%	79%	82%
Electricity	5%	13%	7%
Others	11%	8%	10%
Total	100%	100%	100%

Source: BERR website www.berr.gov.uk/files/file47214.xls

Gas dominates the heating market, with around 80% of energy consumption, compared with electricity's 7% market share. This is broadly consistent with 87% of customers in 2006 using gas central heating, compared with 6% using some form of electric heater[11].

Though space and water heating represents 28% of total residential demand over the year, a large proportion of this demand occurs overnight. However we assume there remains a significant proportion of residential electrical heating load at 5pm. We assume that the heating load and the load of so-called wet-appliances (dishwashers and washing machines) can be time-shifted to occur later than 5pm, the typical time of system peak demand. There is limited detailed information available on the use of electricity by type of appliance on a half-hourly level, and there is a range of uncertainty around both when appliances are used and the extent to which they can be time-shifted. IHS Global Insight estimates that discretionary load represents between 6% and 37% of total residential demand at 5pm, depending upon different assumptions about how customers use their electricity at peak types and the ability to time-shift or forego the use of certain appliances, including heaters, washing machines, dishwashers, heaters, computers, and TVs.

If every single residential customer moved all of their discretionary demand in response to price signals at the demand peak, then the possible range of response is between 1 GW and 6 GW, based upon the estimated domestic load shape as detailed below.

Table 9 – Discretionary Domestic Electricity Load

Domestic demand at 5pm	17	GW
Maximum percentage of 5pm peak:	37%	
Maximum discretionary load:	6	GW
Minimum percentage of 5pm peak	6%	
Minimum discretionary load:	1	GW

Source: IHS Global Insight estimate

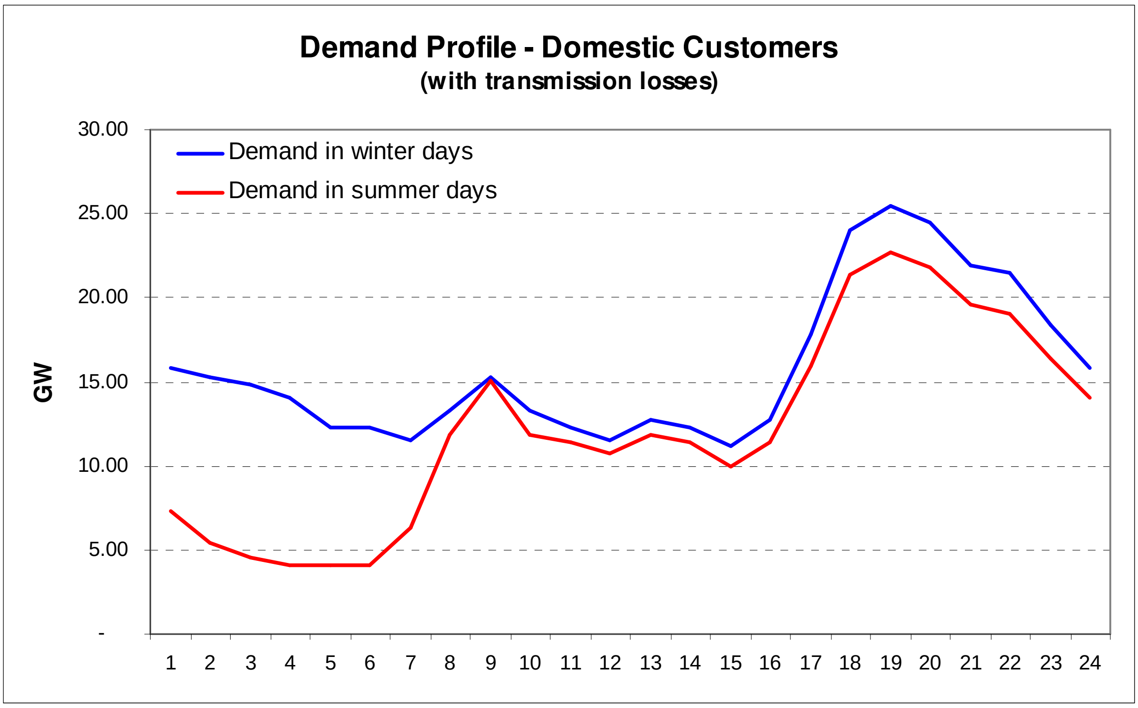
It appears unlik191/R12h11.p04 Tf 0.999404 Tf10.999502 0 53.12187 0 Td (o)Tj 6Td (g)Tj 5.52339 0 Td (h)T

However all consumers do not do everything at the same time, and this diversity factor smoothes out the total load shape of the 25 million residential households.

For those consumers with gas central heating, their peak demand tends to be in the evening, when they are using electricity for both cooking and lighting. Consumers with night-storage heaters typically consume most electricity around midnight, when the Economy 7 tariff starts.

The load shape given below is for consumers on the standard single rate tariff without night storage heating systems. No load profile data has been found relating to E7 customers. We estimate there are 1.6 million E7 customers in total, of which 1 million have night storage systems. These systems typically have a capacity of around 7 kW overnight. The over-night charge is typically around 5 hours

Figure 4 - Domestic Demand Profile



Source: IHS Global Insight estimate

3.3 Commercial & Industrial Sectors

There is a wide variation in the consumption patterns of commercial and industrial customers, though incomplete information makes it difficult to provide precise estimates of the exact variation.

There are 2.4 million Industrial and Commercial customers in GB[12], of which there are 2.2 million small commercial and industrial electricity customers in profile class 3 & 4, consuming below 100 kW. The small commercial and industrial customers typically consume as much a very large domestic customer, and consume annually around 40 TWh, and make up over 10% of the total sales in GB.

Table 10 – Commercial and Industrial customers with demand below 100 kW

Customers	Million	2.2
Consumption	MWh per customer	18
Total Consumption	TWh	39.6

Source – DECC Smart Metering consultation[13]

Based upon the figures provided by DECC, there are estimated to be around 200,000 large commercial and industrial customers, with maximum demand above 100 kW.

3.4 Commercial Sector

Sales

On the assumption that 50% of large customers are commercial, there are estimated to be around 100,000 large commercial customers. The average sales per large commercial customer in this group is around 350 MWh, which is around 20 times that of the smaller commercial customers.

Table 11 – Commercial Sales

Commercial Sales	TWh	75
small commercial sales	TWh	39.6
sales to large commercial customers	TWh	35.4
large commercial customers	Million	0.1
sales per large commercial customer	MWh per customer	354

Source: IHS Global Insight estimate

Use of Electricity

Lighting, computing and catering load make up 60% of demand. This load is likely to be non-discretionary. Discretionary load in the form of space and water heating is only 17% whilst cooling load is only 5%. Ventilation and other load represent 18% of total load. These figures are an average for the year. On an hourly-basis the proportions could be different, but no information has been found on the individual drivers of the half-hourly commercial demand shape.

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12 http://stats.berr.gov.uk/energystats/dukes08_c5.pdf Table 5B

13 http://www.decc.g9 [illegible]

Table 12 – Commercial Sector Electricity Use, UK

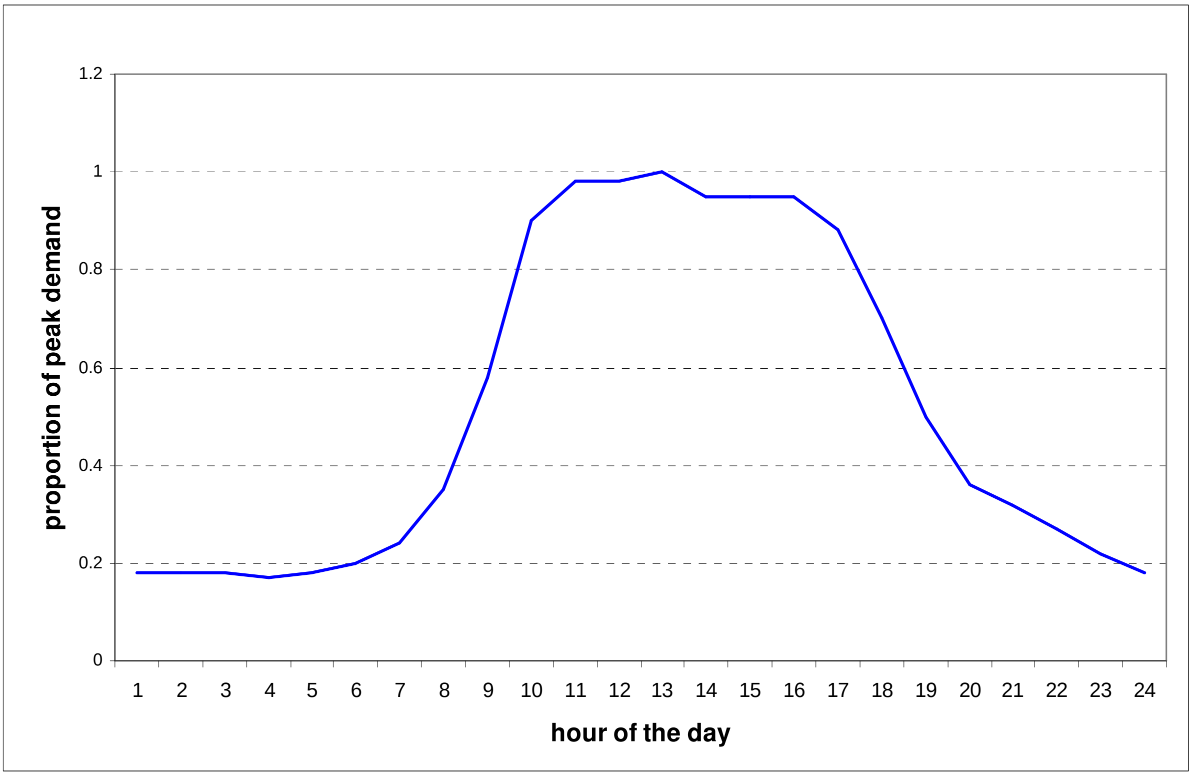
	TWh	% of consumption	load factor	GW	
Catering	13.2	14%	25%	6.04	all year
Computing	5.4	6%	42%	1.48	all year
Cooling (Refrigeration)	4.6	5%	100%	0.52	all year
Ventilation	4.6	5%	65%	1.61	in summer, 0% in winter
Hot Water	3.3	3%	100%	0.38	all year
Heating	14.1	14%	65%	4.95	in winter, 0% in summer
Lighting	39.4	40%	42%	10.79	all year
Other	13.0	13%	70%	2.12	all year
Total	97.6	100%		23.0	Winter

Source: DECC[14].

Load Shape

Figure 5 illustrates the load shape profile for commercial customers, as estimated by IHS Global Insight.

Figure 5 – Commercial Demand Profile



Source: IHS Global Insight estimate

Based upon analysis of the system demand shape, we estimate the typical weekday load for all commercial and public administration customers to be as indicated below.

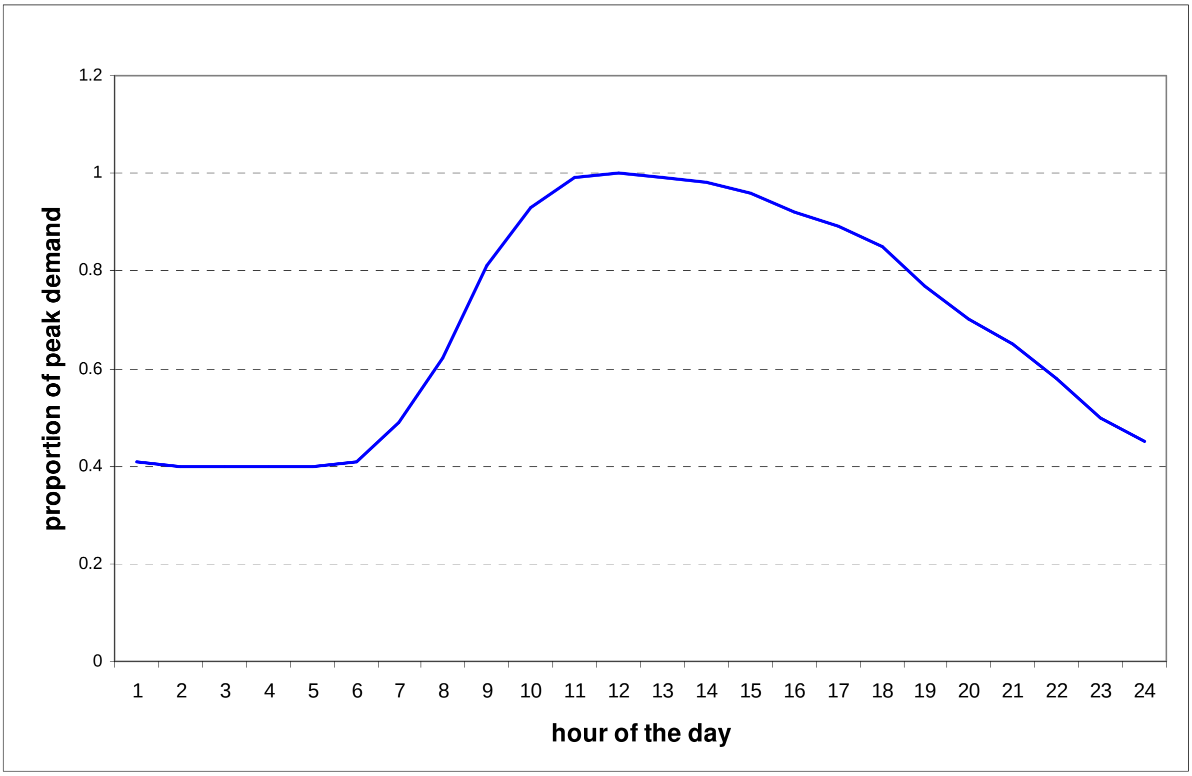
[14] www err gov uk files file4 xls This data in this table relates to the UK, rather than GB.

Process and motor demand make up 75% of industrial demand. Whilst it may be possible to time-shift this load, given the appropriate price incentives, we assume this load is non-discretionary. The heating load is only 9%. These figures are an average for the year. On an hourly-basis the proportions could be different, but no information has been found on the individual drivers of the half-hourly industrial demand shape.

Load Shape

The industrial load-shape, as estimated by IHS Global Insight, tends to be similar to that of the commercial load-shape, but with more over-night load for an industrial customer.

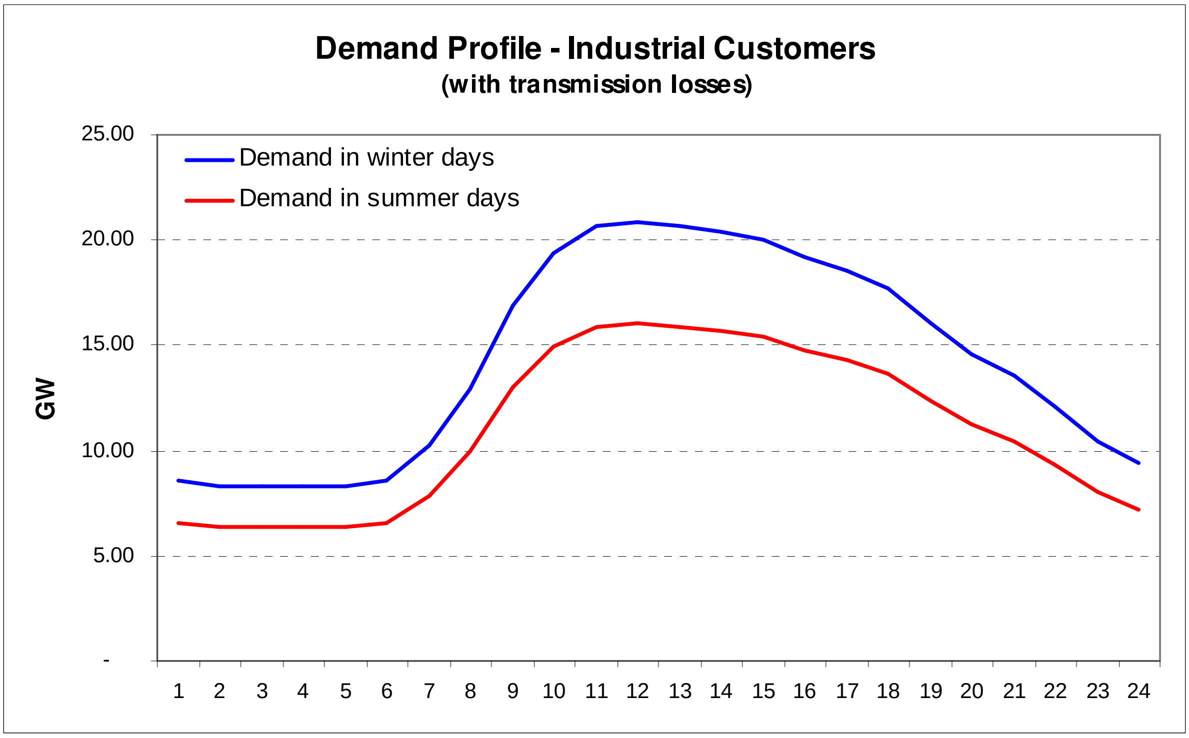
Figure 7 - Load shape profile for medium-sized industrial customers



Source: IHS Global Insight estimate

Based upon analysis of the system demand shape, we estimate the typical weekday load for all industrial customers to be as indicated below.

Figure 8 – Industrial Demand Profile



Source: IHS Global Insight estimate

Discretionary load

As detailed above, we estimate discretionary load in the form of space and water heating load is only 9%. Based upon our estimated industrial demand and our assumption that heating load occurs mainly in the winter, IHS Global Insight estimates there to be 3-4 GW of discretionary industrial load in the winter, as heating load occurs mainly in the winter.

3.6 Summary

The key findings from the above analysis of customer sales and uses of electricity include:

- Huge variety in household consumption levels and patterns;
- Lighting is a major use of electricity, for residential and commercial consumers;
- Little air conditioning (A/C) load in residential sector;
- US and southern European countries have higher levels of A/C load; and
- The volume of discretionary load across all sectors appears to be low.

It is assumed that heating and air-conditioning load are the most significant discretionary loads that can be "time-shifted", but there is clearly a range of other load which customers could reduce or time-shift if they were given a sufficient price incentive. On the basis of its assumptions, IHS Global Insight estimates that there is 9-17 GW of discretionary load.

Table 14 – Discretionary load, GW

	Range
Domestic	1-6
Commercial	5-7
Industrial	3-4
Total	9-17

Source: IHS Global Insight estimate

	Within Day	Dayahead	Yearahead
Static Time of Use pricing (e.g. Economy 7)			
Maximum Demand Tariffs			
Future schemes			
Basic consumption information			
TOU tariffs with dynamic periods			
TOU tariffs with dynamic prices			
Maximum Demand Control			
Direct Load Control			
Electric Vehicles with smart controllers			
Fuel switching			
Low Frequency Relays on certain appliances ("Dynamic Demand")			
Back-up generation			
Distributed generation and storage			

The rest of this chapter describes each scheme in more detail.

4.2 System Operator Led Schemes

4.2.1 National Grid Contracted Reserve (.

terms of the service, some customers were of the view that National Grid could further encourage demand side participation by:

- allowing greater linking of the utilisation price to the price of the underlying fuel; and
- dispatching DSM more often. There is a perception amongst some customers that National Grid at times has a preference for dispatching large conventional generators rather than DSM. This reduces the income available to demand side participants.

These are issues which could be examined by any future review of STOR undertaken by National Grid.

However a large factor restricting the involvement of DSM is the relatively low value of STOR compared with the benefit of uninterrupted electricity supply. For most customers, electricity is a relatively minor cost element. We would expect customers' interest in STOR to increase as the value of the service rises in the future.

4.2.2 Low Frequency Relays (contracted service FCDM - Frequency Control by Demand Management)

National Grid contracts directly with generators and demand side players for the provision of response services. Frequency Control by Demand Management (FCDM) and Firm Frequency Response are both relatively mature services through which National Grid currently procures around 500 MW of response from Demand Side players. Large customers automatically lower their demand when the frequency drops below a certain level.

FCDM, supported by response services from conventional generators, helps maintain the frequency within standards. Response providers help ensure that the system frequency does not collapse when there is a large generation failure. The amount of frequency response held on the system is related to the largest single credible generation loss and the demand level. National Grid is also examining whether high levels of wind generation may increase the required volume of Frequency Responsive generation.

Though increased FCDM may not directly help with tight demand-supply balance, increased levels of FCDM do ultimately free up responsive conventional generation capacity and allows the conventional plant to provide "conventional" reserve, thereby increasing security of supply and reducing the need to construct new capacity.

This service is relatively mature and IHS Global Insight, after consultation with the electricity industry, does not consider there to be many barriers to entry

4.2.3 Triad Charges

National Grid charges suppliers for their customers 'use of the Transmission system on the basis of their demand at times of system peak. The consumer's demand at the time of the system peak on the 3 highest demand days are averaged and charged at around 15,000 £/MW[16]. This charge is equivalent to an energy price of 5000 £/MWh.

National Grid estimates that the Triad charges as currently applied by National Grid reduce peak demand by around 1 GW[17].

Until the early 2000s all customers were charged on the basis of their demand at the time of system peak. It was possible for customers to switch supplier during the winter, and for the supplier to be charged a high Triad bill, yet receive little sales revenue from their customer.

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[16] http://www.nationalgrid.com/NR/rdonlyres/7670F6EE-3945-4E8A-8F9E-068CDC5EA9FA/33162/UoSCI5R0RFinal.pdf

[17] http://www.nationalgrid.com/NR/rdonlyres/4B475A5C-D41A-4039-9089-30B282276577/35406/Winter_Consultation_Report_final_3_.pdf

To address this issue, the charge for smaller customers is now based upon the customer's demand between 3pm and 7pm over the whole winter rather than the 3 peak days.

It is not known what impact this modification has had on peak demand.

4.2.4 Voltage adjustment

Voltage adjustment is achieved through Distribution Operators changing the voltage of the supply they offtake from the Transmission system at Bulk Supply Points (BSP), providing around 1% of demand reduction, as estimated by National Grid, for each percentage of voltage reduction – a reduction of several GW is possible.

Voltage adjustments can affect many types of equipment if deployed for long periods of time, and therefore it makes sense to use it occasionally and on

Other markets such as Nordpool[19] appear to have an active and transparent demand side involvement, which could be due to a large base of electricity-intensive industrial customers. In the UK it is not known with certainty how many large customers currently adjust their demand in response to the market spot price of electricity. There are a variety of different ways customers can be exposed to and benefit from the volatility of the spot electricity price. There is no information available on the extent to which customers actively trade, but based upon informal industry figures, we estimate that currently around 100-200 MW of demand can take advantage of high dayahead electricity prices by lowering their demand.

Most industrial production processes do not support short-notice changes, so dayahead trading and longer notice trading tend to be favoured. In this context, direct customer trading can help deal with anticipated issues, be they caused by a general lack of generation or by wind intermittency.

There are no formal barriers preventing industrial or commercial customers from dayahead trading. As the volatility of power prices increases in the future, it is to be expected that retail suppliers of electricity will increasingly pass-on the price risk to customers, and will encourage and facilitate active trading by customers.

The GB electricity market appears not to be as liquid[20] as other European power markets or the GB gas market. The current electricity Imbalance Charge reflects the average, rather than the marginal, cost of generation as paid by National Grid. It is unknown to what extent either of these factors discourage customers from actively trading.

4.3.2 Customer Participating into Balancing Mechanism

Large customers who can vary their production and demand for electricity at short notice can provide a Demand Side Management service by directly participating in the Balancing Mechanism (BM). The BM is a real time "Market" in which National Grid issues short notice instructions to generators to increase / decrease their output and potentially to large customers to vary their demand in order to maintain the security of the system.

Currently no large customer participates in the BM. There is a cost associated with BM participation, but the main hurdles are considered to be the nature of the short-notice instruction. Few customers can respond in the short time scales required (up to 90 minutes notice but typically around 30-60 minutes) and those who can respond quickly have already contracted their demand reduction to National Grid in the form of the STOR service.

4.4 Existing Supplier led schemes

4.4.1 TOU static tariffs

With Static Time of Use (TOU) tariffs, customers are charged predetermined tariffs prices for using electricity at different times of the day. For residential customers currently on TOU tariffs, there are typically 2 tariffs whilst the largest industrial customers would typically have over 20 different prices across the year, with 3 prices per day, different prices on weekdays and weekends, and prices that vary by season.

Since both the price and the periods of the day/year are fixed, this scheme helps with lowering peak demand / demand shifting across the year but does not encourage

[19] Nordpool is the electricity exchange covering

"active/within day" DSM. Any reduction in peak electricity demand is useful in dealing with a capacity shortfall. However TOU static tariffs provide little direct help with dealing with a problem such as wind intermittency or limited plant availability that occurs outside of the peak periods.

TOU tariffs have been applied to large industrial and commercial customers for many years. It is difficult to know how successful TOU tariffs have been in influencing the behaviour of consumers, but it is likely that the increased price differentials between peak and off-peak periods will lead to further reduction of peak demand.

For smaller customers, including residential customers, with a high proportion of overnight load, the simple 2 rate Economy 7 tariff has been popular, but still represents only 33% of residential demand. It is estimated that there are around 1.7 million residential customers on 2 rate tariffs, around 6% of the total. Of these 1.7 million customers, around 1 million have electric night storage heating systems.

The main barriers to increased take-up of Economy 7 tariffs have been:

- relatively low price differential between peak and off-peak periods; and
- the widespread preference for gas-fired central-heating systems.

The GB government is proposing that smart meters which could support TOU tariffs should be installed at all domestic sites by end 2020 and that smart or advanced meters should be installed at smaller non-domestic customers' sites by end 2020. These proposals are currently the subject of consultation.

There is limited international experience of the introduction of TOU tariffs for the residential and small commercial sectors. However the successful application of the 2 rate Economy 7 tariff in GB in the 1970s and the adoption of storage heating imply that it is possible for consumers to respond to price signals and to significantly alter their consumption patterns.

4.4.2 Maximum Demand Tariffs

With Maximum Demand Tariffs, customers pay a higher fixed charge according to their maximum demand. Maximum Demand tariffs in a variety of forms already exist for large and medium customers, whose maximum demand is over 100 kW. They typically reflect the Maximum Demand charges set by the DNO, who charges for the use of assets. In addition to recording the total electricity consumption, special meters record the customer's highest half-hourly demand, over different periods of the year.

As it is a long-established practice for DNOs to charge large-medium customers a Maximum Demand Charges it is not known how much demand has been suppressed by Maximum Demand tariffs.

In Italy and France, residential customers are subject to Maximum Demand tariffs, with customers paying a higher fixed charge according to their maximum demand[21] [22]. This appears to be successful in limiting peak demand, with residential customers appearing to choose demand limits at levels lower than are typical in GB.

Extending the scope in GB to residential and small commercial customers may require the installation of suitable meters, which can record the customer's maximum instantaneous

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[21] http://www.edf-bleuciel.fr/accueil/j-ai-besoin-d-energies/electricite/les-tarifs-electricite-141626.html

[22] More information on Italian smart metering developments can be found at: http://www.europeanenergyforum.eu/upload/Presentazione%20Telegestore%20parlamento%20europeo%20v%201.pdf

demand. The smart metering proposals currently being consulted upon by DECC do not mandate this functionality.

The DNO Maximum Demand Charge tends to limit the overall maximum demand of the customer over the whole year, and encourages peak-lopping. Maximum Demand tariffs are not suitable for dealing with short-notice Reserve or Availability issues.

4.5 Scheme developments

4.5.1 Basic consumption information

Basic consumption information can be given to all customers in a variety of ways: information printed on the electricity bill, clip on devices, e-mail, on-line or personal contact. These can be accompanied by electricity saving advice or not. The provision of such information is best achieved via a "Smart Meter", which in addition to allowing remote meter reading facilitates the direct provision of more detailed consumption information to the consumer.

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The international and GB experience[33] show that, initially, the customer response is usually around 1-5% of energy demand. Though these measures usually encourage an overall consumption reduction, the reduction in peak demand tends to be of a similar magnitude to the overall energy reduction. DECC's Smart Metering consultation assumes that smart meters with a real-time display will give an energy saving reduction of 1-5% for electricity, with a central estimate of 2.8%. Such reduction in electricity demand is useful in dealing with a capacity shortfall, as the reduction in peak demand helps to improve the demand-supply balance. However general reductions in energy demand provide little direct help with dealing with short notice Reserve or Availability issues problems that occur within day or Day-ahead.

A further issue with prolonged/sustained reductions in electricity demand is the market reaction. If the market reacts to lower demand levels by constructing less capacity, then the level of security of supply may be essentially unchands

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TOU metering systems with the ability to communicate clear price messages to the consumer are necessary, as the consumer would need to be informed of the application of the higher prices. The demand reduction depends on the price difference between periods, on the ability to consumers to respond to price signals, and on the willingness of consumers to migrate to these more complex tariffs.

The GB government is proposing to make the provision of smart meters mandatory for all domestic customers and more advanced for small and medium non-domestic customers. It appears that these smart and more advanced meters could support TOU tariffs.

4.5.3 TOU dynamic tariffs

In this scheme, besides the dynamic periods, the prices would also vary, and would be communicated to consumers. This would be very similar to being exposed to the spot price, which is already an option for large customers. This scheme would not be practicable to a wider range of customers until they have access to the relevant price information. Customer response is expected to be larger the longer notice given, so it is anticipated that prices would be set day ahead but in theory they could be set at any time, including up to Real Time if this were proved to be cost effective in terms of the benefits against the costs of the communication provision.

This scheme would probably be too complex for residential customers. It was successfully implemented in Norway[25], and offered to commercial and residential customers, although automatic load control had a crucial role in the success of this scheme. The major obstacles to the increased use of dynamic tariffs are the requirement for consumers to monitor the "live" prices, and the risk element involved. It is simpler and more practical to sign on to a fixed price tariff, rather than be exposed to a volatile and unknown electricity price.

The advantage of TOU dynamic tariffs is that they can be flexible and can respond to developments. In the UK they would be helpful with a range of situations, from a low yearahead plant margin to a tight dayahead margin. As a notice period of at least several hours would be expected, TOU dynamic tariffs would not be sufficiently flexible to deal with short-notice Reserve issues.

4.5.4 Maximum Demand Control

In a Maximum Demand Control scheme, the system operator (or the supplier or DNO) would remotely cap the maximum demand allowed through the customer’s meter, as required at times of tight supply-demand balance. If the customer exceeds the maximum demand permitted, the electricity would be cut off, until the customer reduces the load within the limit.

It is more common to have Maximum Demand Tariffs, such as occur in Italy and France, rather than to have Maximum Demand Control. Whilst Maximum Demand tariffs are static, with the limit applied throughout the year, Maximum Demand Control is more selective and is applied only during periods of tight demand-supply balance. Other international experience tends to be of direct load control of certain appliances, rather than Maximum Demand Control per se.

In GB, there has been no experience of Maximum Demand Control, due to a variety of reasons:

- GB has historically enjoyed good to high plant margins;

[25] http://www.ieadsm.org/Files/Tasks/Task%20XV%20-%20Network%20Driven%20DSM/Publications/IEADSMTaskXVResearchReport1_Secondedition.pdf

- Though in GB air-conditioning load has increased, this has been against a general background of improving energy efficiency and only a moderate growth in overall power demand;
- the distribution infrastructure is sufficient to meet a high demand from residential customers; and
- Technology is relatively new (only a few years old).

There is scope for Maximum Demand Control to provide significant levels of DSM, but in reality it is difficult to see consumers willingly signing on to a tariff that reduces their ability to consume electricity, even if there was a significant financial saving. There is a wide diversity of electricity demand in GB, but the high users of electricity may well be the ones wlo 2.40 R4 0 Td (n)Tj 6.1

The use of Low Frequency (LF) Relays reduces the need for National Grid to hold Response on other providers. This allows the generation and other DSM providers to provide increased levels of "conventional" reserve, thereby increasing security of supply. It can be useful in dealing with Reserve issues, and can be considered a selective demand control measure, as only certain appliances are disrupted.

It is not known whether the market will independently introduce these relays, or whether they will be become mandatory via some form of minimum standard. Considering the time for penetrations of these appliances in the market, this is a medium to long term implementation scheme.

4.5.7 Electric vehicles with cut-offs / smart controller

The increasing take-up of plug-in electric vehicles represents an opportunity to increase DSM. Though the technology remains under development, there appears to be increasing take-up, supported by government interest, with the UK government unveiling plans in April 2009 to support electric vehicles (EV) in order to lead a revolutionary shift to low-carbon transport in Britain, with a planned incentive of up to £5000 per electric car.

Though the future technological development remains uncertain, including the relative importance of hybrid versus plug-in EV and the battery capacity, we have used an estimate of 3 miles per kWh of charge – i.e. 9 kWh charge for a 27 mile range[28]. Charging is expected to occur not at the peak, but between 6 pm and midnight and possibly over-night depending upon the price incentives and drivers 'behaviour patterns.

We expect that charging of EVs would be demand-managed by the supplier or National Grid, via a plug / socket controlled by radio teleswitch. The government proposals on Smart Metering for residential customers should facilitate this.

As little charging is expected during peak periods, EVs with cut-offs are not foreseen to help much with a tight capacity balance during peak periods. However the direct control of EVs during charging periods could help deal with an on-the-day reserve issue. It is estimated that 1 million cars charging randomly during the 6 hour evening slot would provide 1.5 GW of instantaneous DSM. However the DSM response could not be maintained for a long time as the batteries would have to be charged at some point, and there may be issues associated with the pick-up in demand when the charging is resumed.

4.5.8 Fuel switching

There is limited scope in GB to switch away from electricity to other energy inputs. The residential space and water heating market is already dominated by gas, and where electricity is used for heating, it is predominately during off-peak periods.

There is scope for residential customers to switch over from electric ovens to gas ovens in the medium term, but it is difficult to envisage customers actively switching between fuels depending upon the market spot price of electricity as it is highly unlikely that customers would incur the additional significant cost of the second “back-up” appliance.

There may be scope for the commercial sector to move away from electricity to gas heating, but it is difficult to see this switching being "dynamic", and hence it would not be that suitable for dealing with an on-the-day reserve issue.

Switching from electricity to renewable sources of heat energy is also likely to be a permanent switch, not a dynamic response suitable on-the-day issues.

[28] http://www.nationalgrid.com/NR/rdonlyres/328

Conversely it is more likely that there is switching to electricity away from other fuels. Electric vehicles have already been discussed, but air and ground heat pump are emerging technologies which increase electricity demand.

The following schemes are not strictly DSM as such as they involve generation rather than reducing or time-shifting demand but they are discussed here for completeness.

4.5.9 Distributed/Back Up generation

Customers can provide DSM via the use of distributed or back-up generation. They can directly lower their electrical offtake from the Grid, through the use of their own generation, thereby avoiding high Time of Use Tariffs or they can sell this flexibility to National Grid via the STOR contract.

Back-up generation can be utilised at short notice, so it is helpful in dealing with issues such as within year availability and on-the-day reserve, as well as yearahead margin issues.

The decision to invest in and use Back-Up generation is influenced by many factors;

- the level and volatility of wholesale power prices;
- the additional value obtained from selling the flexibility of the back-up generator to National Grid or the market generally ;
- the avoided distribution and transmission charges;
- the cost of the investment;
- the cost of the back-up fuel; and
- the value of un-interrupted supply. Back-up generation may be attractive for those customers who value continuity of supply highly. Typically GB customers are off-supply for around 1 hour per year.[29]

If the first 2 of these factors increase in the future this should encourage industrial and commercial customers to increasingly consider investing in Back-Up generation.

4.5.10 Stand Alone Generation & Storage

Small stand-alone generators or storage systems such as blocks of batteries could be used to supply distribution networks. This is not strictly speaking demand-side response, but does get categorised as such sometimes because such generation or storage can be used to avoid transmission constraints or handle other distribution-level problems such as voltage support. However, the high cost of most storage systems and the increasing returns to scale imply that the benefits of using stand-alone generation and storage to deal with large system-level problems are limited, judging by the lack of wholesale development of these. Distribution companies already have incentives to contract for such systems when needed to address local problems.

Pumped storage schemes and hydro with storage capacity have traditionally been used to shift energy from peaks to trough periods. If the price differential is sufficiently large then it will be economic to pump and store energy during the night feeding it back during peak day time periods. The price differential needs to be sufficiently large to offset the efficiency loss of about 30% with pumped storage. Storage can help to manage peak capacity issues, but in many ways its best application is dealing with wind intermittency. In Japan it has been

[29] Electrica Services Limited, based upon Ofgem analysis

made mandatory for all wind farms to have associated storage facilities. In the UK in addition to the existing pumped storage generation, consideration has been given to pressurised air storage under-ground but the estimated costs at this stage of development appear high.

The penetration rate of small scale stand alone generation units would be expected to increase from the current low levels as the value of flexible Reserve capacity increases, and as the costs of the technologies fall.

5 Review of Selected DSM Techniques

The schemes reviewed in Chapter 4 range from mature schemes, which the Government can only play a relatively small part in further supporting, to schemes whose potential remains high but whose development remains uncertain.

The expected developments in the electricity industry are likely to lead to increased levels of DSM, as the value of flexibility increases. The developments in metering systems, control electronics and the Government's recently announced Smart Metering proposals should further encourage the growth of a variety of Time of Use tariffs, and Direct Load Control schemes.

The following DSM schemes have been analysed in greater depth so as to assess their potential effectiveness in addressing security of supply problems:

- More sophisticated TOU Tariffs, including multi-rate tariffs to residential customers and the provision of more dynamic price signals to customers.
- Maximum Demand Tariffs and Maximum Demand Control.
- Direct Load Control.

Different DSM schemes address different types of problems and can be used in different situations. It is also possible that different DSM schemes can be deployed simultaneously.

Chapter 6 considers the benefit of the further DSM, in the form of deferred investment, increased security of supply and energy cost savings.

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5.1 Common Issues

There are some issues common to the 3 broad DSM techniques, which are discussed generically in this section.

5.1.1 Deployment

s thity

5.1.4 Unintended consequences

It is possible that the complete range of tariffs is not offered to all customers. Further as customers with high off-peak demand migrate to TOU tariffs, the price of the single rate electricity tariff will increasingly reflect the cost of peak electricity. This may become an issue for the fuel poor.

5.2 Time of Use Tariffs

5.2.1 Barriers and Incentives

Consumers have been able to choose TOU tariffs in GB for many years, and multi-rate TOU tariffs are widespread for larger commercial and industrial customers. Small and Medium Enterprises (SMEs) and residential customers tend to be offered simple 2 rate tariffs, and the take-up has not been high for customers without a high volume of over-night load, as the price incentive to switch tariff has been low, compared with the effort involved. Currently only around 7% of residential customers are on such TOU tariffs, and the share of domestic demand has been stable over the past few years at around 33%.

As discussed previously it is expected that the developments in the generation sector will increase the value placed upon DSM by suppliers. Developments in metering arrangements will also encourage suppliers to offer:

- TOU Tariffs with increased price differential between peak and off-peak periods; and
- More sophisticated tariffs which divide the year into more periods, including Critical Priced Periods (CPPs)

With TOU tariffs with Critical Peak Periods (CPP), the tariff is pre-defined and fixed, but the periods when each tariff is applicable can vary. In these schemes, the international experience is that customers are informed day-ahead of the most expensive periods. Examples of this scheme were successfully implemented in France and California, both to cope with peak loads resultant from weather conditions. California has high A/C load, whilst rural France uses significant amount of supplemental electric heating during abnormally cold periods. To deal with GB issues, such as low plant availability and wind intermittency, an adaptation of the scheme would be necessary. International experience shows that this scheme is more effective when combined with some kind of automatic load control.

The introduction of Smart Meters should reduce the effort involved in switching to TOU tariffs as no further change in meter will be required and the proposed metering arrangements should facilitate more sophisticated TOU tariffs. Though both of these factors should encourage more customers to take up TOU tariffs, the financial saving would have to be significant to overcome consumer apathy, and this trade-off between cost and effort remains the biggest barrier to the widespread adoption of TOU pricing for the residential and small commercial sectors.

Though the GB government is proposing to make the provision of smart or advanced meters mandatory for all customers it is not clear whether the current proposals would include the dayahead notification of expensive CPP tariffs. TOU metering systems with the ability to communicate clear price messages to the consumer are necessary, as the consumer would need to be informed of the application of the higher prices.

It is estimated that there is between 1 and 6 GW of discretionary residential load in GB. The roll-out of Smart Meters should increase the level of DSM, but there are some important factors to consider:

- The exact level of response is likely to vary depending on the price differential between the TOU periods.
- Consumers switching tariff firstly have to understand the range of tariffs offered by different suppliers, choose the right option, then notify the supplier and fill in the appropriate forms. Finally the consumer needs to adjust his behaviour. All these steps involve effort and time. The financial saving would have to be significant to overcome this consumer apathy, and this trade-off between cost and effort remains the biggest barrier to the widespread adoption of more sophisticated TOU tariffs.
- The willingness-to-respond is not known for either commercial or residential customers in GB.

5.2.2 *Application circumstances*

Simple TOU tariffs are most suited for dealing with problems that arise year-ahead as they reduce peak demand, so called peak lopping. The periods tend to be set well in advance, and so simple TOU tariffs are useful for dealing with the standard periods of high energy demand in the winter and to a lesser extent the peak daytime hours on business days throughout the year. They are only helpful in dealing with the day-ahead issue if these situations arise during the pre-set peak periods. A with-in day problem requires a dynamic response, which cannot be provided by static prices and periods.

More sophisticated TOU Tariffs are also suitable for problems that arise year-ahead, as they s mtOcl (a

This arrangement will not be sufficient for CPP tariffs, as we assume consumers will need to be notified of changes to the TOU periods at least dayahead. It is not clear the degree to which the proposed Smart Metering systems under being consulted upon would facilitate this form of tariff.

5.3 Maximum Demand Tariffs and Maximum Demand Control

5.3.1 Barriers and Incentives

With Maximum Demand Tariffs (MDT), the customer would choose what level of demand they would be willing to pay for. The higher the demand limit, the higher the fixed fee. If the customer exceeds the maximum demand permitted, the electricity would be cut off, until the customer reduces their load within the limit.

Larger commercial and industrial customers already have the option to sign on to tariffs which exhibit many if not all the significant characteristics of Maximum Demand Tariffs.

In a Maximum Demand Control (MDC) scheme, the system operator (or the supplier or DNO) would remotely cap the maximum demand allowed through the customer's meter, as required at times of tight supply-demand balance. It is essentially a more dynamic form of Maximum Demand Tariff. If the customer exceeds the maximum demand permitted, the electricity would be cut off, until the customer reduces the load within the limit.

The average residential demand across all 26 million residential customers is around 0.8 - 1 kW at peak times but this hides a wide degree of diversity. The maximum demand of any one customer during the year is considerably higher, probably over 10 kW for a large residential consumer. Each consumer's demand pattern is different, as people do things at different times, and this allows for a smoothing or diversity effect.

It seems likely that several GWs could be available from all customers if the maximum demand level was set sufficiently low, but it is not clear how many consumers would be willing to sign onto such a tariff. It would seem unlikely that many customers, be they residential, commercial or industrial, would voluntarily sign on to this form of tariff. GB customers have had a reliable and "limitless" supply of electricity since the early 1970s, and their dependence on electricity has increased significantly. We assume customers would only sign onto a MDC tariff if the tariffs were subject to a large discount or the MDC tariffs were compulsory.

For the suppliers there would be a degree of risk, as they do not know precisely how their customers would change their demand profile in response to the MDT or MDC tariff.

Consumers' high value of electricity is the biggest barrier to the widespread adoption of Maximum Demand Control. Though the mandatory introduction of Smart Meters may make consumers more aware of how much and when they are consuming energy, the take-up in this tariff is expected to be very low.

5.3.1 Application circumstances

Maximum Demand Tariffs are suitable for Yearahead issues, as they encourage peak-lopping. As MDT do not respond to short-term developments, they are less useful in addressing Dayahead and With-in Day issues.

Maximum Demand Control has an instant response, and can be planned to be used in advance of the actual time it is required to be used. Though it is suitable for all 3 issues – Yearahead, Dayahead and With-in Day – it is most suitable for with-in day issues. It does not have to be applied continuously, and can be dynamic. But whenever it is used it may be unpopular with consumers, even for those customers who have voluntarily switched to the tariff.

5.3.2 Lead Time

Maximum Demand Control can be applied at any time with no notice, but it would be more acceptable for the consumer to have a few hours prior notice. This is dependent on customers being able to respond.

5.4 Direct Load Control via Plug-In Devices

5.4.1 Barriers and Incentives

With direct load control, the system operator or the supplier can remotely disconnect customers' appliances or reduce the consumption, for example change the temperature setting in a thermostat, of the appliance.

The development of plug-in devices/controllers which cut off supply to appliances upon receipt of a signal from a Smart metering system will encourage the growth of this form of DSM

Consumers ' high value of electricity is the biggest barrier to the widespread adoption of Direct Load Control. The mandatory introduction of Smart Meters may make consumers more aware of when they are consuming energy and make TOU tariffs more attractive, than Direct Load Control via Plug-in Devices. As a result, take-up of this measure may be very low.

Although Direct Load Control offers a great potential benefit, the nature of British electricity consumption, with most heating being supplied by gas and limited use of air conditioning, means that few additional customers are expected to switch to these tariffs.

Industrial and commercial customers with a large heating or cooling load can benefit from DLC, but such customers are already incentivised to economise on their energy bills. The new devices which automatically cut off supply to selected appliances will further incentivise time-shifting of demand.

5.4.2 Application circumstances

The demand reduction may not be able to be sustained for long periods of time. Commercial customers would not be willing to continue to reduce demand if they saw production or sales decline. Direct Load Control may be best suited for peak lopping during the winter, and for short duration and short notice DSM in response to wind intermittency.

5.4.3 Lead Time

Direct Load Control can be applied by any time with no notice, but it does require consumers to have the ability to respond to the supplier instruction. The consumer would need to have purchased and fitted the devices/controllers.

5.4.4 Applicability

Smart Metering could allow Direct Load Control to be applied to all consumers, but it is most likely to be applied to commercial load, and those customers with half-hourly metering, as the supplier would have confidence that consumers are actually reducing their demand.

6 Valuation of DSM

This chapter looks at the benefits of additional DSM.

6.1 Financial Savings

The savings associated with DSM measures such as TOU tariffs, Maximum Demand and Direct Load Control (DLC) are directly influenced by the price differential between the peak periods and the off-peak periods. This price differential is driven by 2 similar but different factors:

- Marginal fuel and EU Emissions Trading Scheme (ETS) cost; and
- Capacity Value - cost to the industry of providing conventional generation capacity

The price differential between peak and off-peak tariffs also reflects how distribution and transmission charges are applied. However we do not consider this element in our analysis, as investment in the distribution and transmission infrastructure is not assumed to be significantly reduced by increased levels of DSM.

The maximum demand of residential customers does not typically occur at times of system peak, but typically occurs later on in the evening. Lower demand at times of system peak is not assumed to significantly reduce the Distribution infrastructure required to meet customer demand. We have assumed that the Distribution companies continue to recover the same overall revenue, and there is no direct benefit for the Distribution companies from increased levels of DSM.

The situation for Transmission infrastructure is more complicated, as arguably lower residential demand could lead to less infrastructure investment by reducing growth in peak demand and thus delaying, or eliminating, transmission investments needed to supply new peaks. There is also a very slight chance that in some specific situations a reduction in residential demand could so influence power flows on the transmission network that increased investment might be required to keep the system in balance. Given the long term nature of transmission investment, it would take some time for the transmission companies to respond to the lower demand levels brought about by increased DSM. Therefore, overall we assume that the revenue recovered by the transmission owners is unchanged as a result of increased DSM. Note that any reduction in electricity demand would lead to an increase in the unit rate in the medium-ter [illegible] days. On peak days, demand may only be shifted by a few hours. Depending upon the price of gas, coal and EU ETS allowances, the marginal cost of generation can vary typically by around 30-40 £/MWh between peak and off-peak periods on the same day.

Historically, the wholesale price differential between peak and off-peak market prices on the peak days has been higher than this, as it also reflects the value of capacity.

It is estimated that **1 GW** of DSM will deliver **10-15 £m** of fuel and EU ETS cost savings due to the more efficient use of the generation fleet, based upon the assumption that demand is time-shifted rather than foregone completely.

Capacity Value

The benefit of additional Demand Side Response can be either measured as the savings associated with deferred investment in conventional generation or the value of increased security of supply, as measured by a lower loss of load probability (LOLP)

Deferred Invest ent

All 4 DSM measures are expected to reduce the requirement to invest in conventional generation capacity. Historically, the existing DSM schemes have helped to reduce demand at peak periods, this is known as "peak-lopping". When making investment decisions, the UK electricity generation market appears to be confident that DSM will continue to occur at the typical periods of high prices, i.e. winter weekdays, and invests in capacity, based upon a demand forecast that assumes DSM. Over time, as the market becomes more familiar with and confident in the increased levels of DSM, it is expected that the market will reduce the level of investment in conventional generation capacity accordingly.

Historically, CCGTs have been the preferred technology for new capacity in the UK, and most planned fossil-fuelled capacity continues to be CCGTs. Though Open Cycle Gas Turbines (OCGTs) have a lower capital cost, the industry has found the higher efficiency of gas-fired CCGTs to be a major factor supporting CCGTs. The cost and ease of borrowing are issues which make it difficult to translate a one-off Capital cost to an annual cost, but IHS Global Insight estimates annualised capital cost of a CCGT to be around 50 £/kW. In addition there are the annual recurring costs associated with staffing, business rates and transmission charges. We have estimated fixed costs to be typically 25 £/kW per year, and so a new CCGT typically incurs around 75 £/kW in total fixed costs, including Capex costs, per year.

National Grid currently spends on average around 50 £/kW procuring short notice "flexible" reserve from a range of providers. This is forecast to increase in the future as the gas turbines at LCPD coal stations close and as the requirement for Short Term Reserve increases, due to wind intermittency.

Based upon the estimated costs of conventional CCGTs and the costs incurred by National Grid in procuring Short Term Reserve, our central estimate of the Capacity Value of DSM has been assumed to be in the range 50-75 £/kW pa. For the first **GW** of additional DSM that the market could confidently rely upon at times of high demand, there would be a gross savings of **50**-**75 £m per year** from deferred investment in conventional capacity.

Increased Security

In the medium to long-term, the market is expected to adjust to the increased levels of DSM by building less conventional generation capacity. However, in the interim, higher levels of DSM increase Security of Supply, and increase the likelihood of demand being met in full.

The loss of load probability (LOLP) is a measure of the probability of not meeting demand in full. LOLP depends upon many factors, and there is not a direct and unambiguous relationship between the Capacity Margin and LOLP. Random events, such as unexpected prolonged periods of generation unavailability or abnormal weather patterns, can significantly influence LOLP.

Historically in GB, though there has been no loss of load directly attributable to low plant margins, on several occasions each year National Grid considers there to be an increased probability of Loss of Load, and issues one of several warning messages, depending upon the severity of the probability.

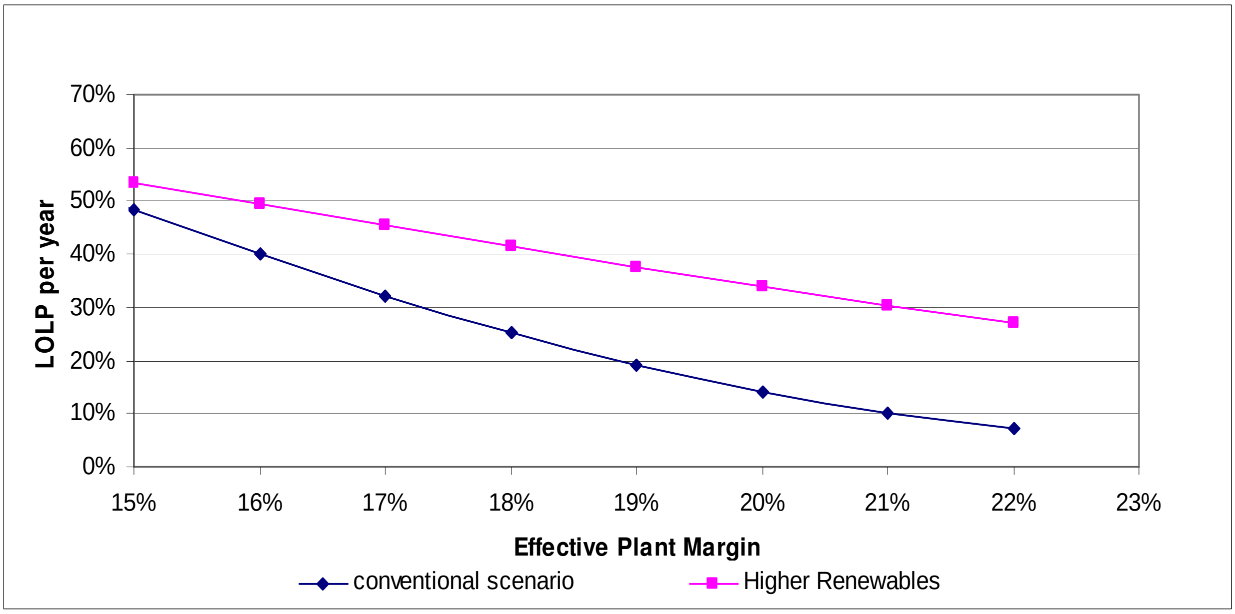
We created a simple model, calibrated against recent experience, to illustrate how LOLP is a function of plant margin and how increased levels of DSM can reduce LOLP. This model clearly does not attempt to reflect what is a very complicated relationship, but does attempt to show how the value of DSM to system security increases when the capacity margin is lower.

Electricity demand has been found from analysis of recorded data to take the form of a normal distribution.

Figure 10 – Capacity Margin - LOi

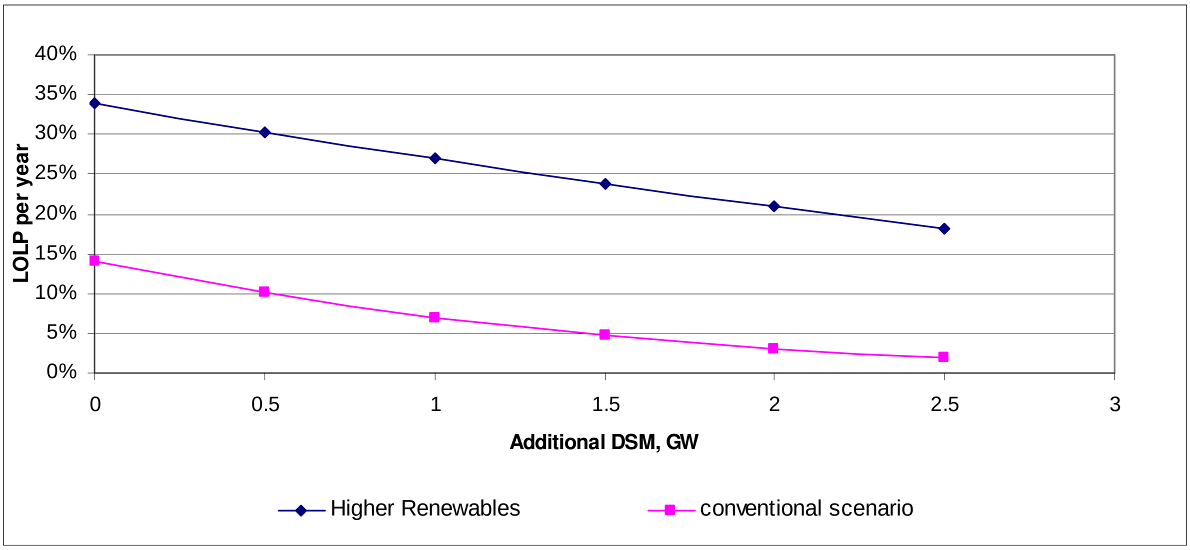
how LOLP is affected by different generation mixes even though the "effective" plant margin remains the same. Under the assumptions made for the High renewables scenario with a 20% plant margin and a high level of wind capacity, there is estimated to be a 34% chance of not meeting demand in full each year, with the current levels of DSM. In a scenario that broadly reflects the current generation mix i.e. a lower level of installed wind capacity, there is a 15% chance of demand not being met in full.

Figure 11 – Capacity Margin – LOLP - Scenarios



The LOLP under the Renewable Scenario is considerably h6Re0 Td (r)Tj 3.72223 0 Td (i)Tj 2.40144 0eTd (o)T

Figure 12 – Impact of DSM on LOLP



When National Grid considers the risk of not meeting demand in full to be high, the DNOs are instructed to apply "Demand Control" measures, which normally means reducing the voltage. National Grid asks for a 5% reduction in demand, which is 3 GW at the time of the 60 GW peak demand, and this demand reduction is achieved by voltage reduction. We assume this only lasts for 1-2 hours in the winter as the demand falls quickly enough after the peak to allow National Grid and the market to recover the situation/meet demand in full. In the summer the flatness of the demand profile may mean that the demand control lasts longer. To reflect the uncertainty, an average of 3 hours has been assumed. This 3 GW of demand for 3 hours, i.e. 9 GWh, is involuntary and is not DSM as such. It is difficult to put a value to voltage reduction but we have assumed it is equivalent to a loss of supply and valued it at 10 £/kWh.

Under the Renewable scenario, a 34% chance of demand control implies that there will be on average 3 GWh of demand lost per year. 1 GW of additional DSM is estimated to reduce LOLP to 27%, implying that on average there will be 2.4 GWh of demand lost per year. The value of 1 GW of additional DSM is therefore 0.6 GWh, the difference between 3 GWh and 2.4 GWh. At 10 £/kWh, this implies an annual benefit of around 6 £m for the additional 1 GW of DSM.

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As discussed earlier, the cost of conventional generation capacity or of short-notice Reserve as purchased by National Grid is considerably higher at 75 £/kW per year. In the subsequent discussion, the value of increased levels of DSM is assumed to the 75 £/kW savings associated with deferred investment, rather than the increased Security of Supply.

6.2 Generic Costs

With mandatory Smart Metering systems proposed for all consumers, the additional direct marginal cost of the DSM schemes such as Time Of Use tariffs, Maximum Demand and

Direct Load Control (DLC) are considered to be relatively low. The main costs to the consumer are:

- the effort involved in understanding the complexity of the range of tariffs;
- the act of changing tariffs;
- the inconvenience, both financial and in time/effort, in actually time-shifting or reducing demand; and
- For DLC, the cost of devices/devices that shut off power upon instruction from the Smart Meter.

It has not been possible to estimate the financial cost associated with these 3 behavioural issues.

Improved / updated profiling of residential and SME load would be required to reflect the changes in the load shape due to TOU, Maximum Demand and DLC tariffs. The magnitude of such costs is not known, but they are not considered to be significant. The widespread use of Smart Meters which recorded half-hourly demand should reduce the cost and need for such profiling.

6.3 Summary and Conclusions

The key findings from the analysis of customer sales and uses of electricity are:

- The volume of discretionary load across all sectors would appear to be lower in GB than in other countries where DSM techniques are widely used (e.g. USA, southern Europe), since GB has:
  - less extreme weather, and therefore less air-conditioning load, than these countries; and
  - a high use of natural gas to provide heating, and less reliance on electricity to provide heating at peak times.
- The high value placed upon time, and the use of electricity – consumers are unwilling to inconvenience themselves for a small financial saving when the effort / time required is high

Overall it is estimated that there is in total around between 9 and 17 GW of "discretionary" load in GB, which can be "time-shifted" to a different time period or foregone completely.

The report explores the benefits deli

Appendix I Evaluation of Options – Summary Table

System operator schemes
Customer/market based schemes
Supplier-based schemes
Various potential leaders

	Problem Addressed				Led by:				Target Customers (see below for numerical breakdown)			Implementation Timeframe			Frequency and Duration (of interruption)		Notice period of instruc-tion	Barriers/practical issues	Market impli-cations
	Wind Intermittence	Peak Load	Inflex-ible gener-ation	Energy Conser-vation	Nat-ional Grid	Supp-lier	Exist-ing	Prop-osed	Large custom-ers	Small Industrial/ Commercial	Resid-ential	Short Term (< 1 year)	Medium Term (1- 5 years)	Long Term (>5 years)	Typical freq-uency per year	For how long?	Day-ahead, Hours-ahead or Instant-aneous		
National Grid Contracted Reserve (STOR) - demand reduction and back-up generation	✔	✔			✔	a	✔ For large		✔	✔		Already exists			typically around 10-100	Until back-up generation comes on	Hours	Need to demonstrate capability and want to cut load. Aggregation issue for small users.	
Low Frequency Relays (contracted service FCDM - Frequency Control by Demand Management)	✔	✔			✔		✔		✔			Already exists			typically around 100	Until back-up generation comes on	Instantaneous	Need to demonstrate capability and want to cut load. Aggregation issue for small users.	
Low Frequency Relays on certain appliances	✔	✔			✔			✔	✔	✔	✔		✔	✔	Depends upon LF setting. Typically around 100	Until back-up generation comes on	Instantaneous	Takes a long time to roll out as fridges are replaced.	Is it mandatory? Who pays for it?
Interconnection shared reserve	✔	✔	✔		✔		✔		NA			Already exists			?	Until back-up generation comes on	Instantaneous	Market rules influence ability of National Grid to access link in real time	
Voltage adjustment	✔	✔			✔		✔												

	Problem Addressed				Led by:				Target Customers (see below for numerical breakdown)			Implementation Timeframe			Frequency and Duration (of interruption)		Notice period of instruc-tion	Barriers/practical issues	Market impli-cations
Customer participating in Exchange/ bilateral trading	✔	✔	✔		NA		✔ For large		✔			Already exists			Depends on customer pref	Depends on customer pref	Day-ahead	Bidding is complex, only for sophisticated customers.	
Customer Participating in Balancing Mechanism	✔	✔	✔		NA		Ability to do so, but in practice no		✔			Already exists			Depends on customer pref	Depends on customer pref	2 mins	Bidding is complex, only for sophisticated customers.	
Basic consumption information		✔		a		✔	✔	a	✔	✔	✔		a		NA		Monthly	Reliability of meters, getting customers to pay attention	No impact
TOU static tariffs		✔	✔			✔	✔		✔	✔	✔	If already have TOU tariffs then immediate, otherwise medium-term			prices typically set annually	NA	Months	Need TOU meters for residential customers.	Elexons ' load profiling may have to change
TOU dynamic periods	a	✔				✔		✔	✔ (existing D-1 market)	✔	✔		a		20 days per year?		D-1 - for large users	Customers need to be monitoring periods to respond to signal. Someone needs to send signal.	Who sends signal? Simple process preferable.
TOU dynamic tariffs	✔	✔				✔		✔	✔	✔	✔		✔		10 days a year?	4-hours	H-1 - for large users	Customers need to be monitoring prices to respond to signal. Someone needs to send signal.	Who sends signal? Simple process preferable.
Maximum Demand tariffs		✔				✔	alarge & medium customers		✔	✔									

	Problem Addressed				Led by:				Target Customers (see below for numerical breakdown)			Implementation Timeframe			Frequency and Duration (of interruption)		Notice period of instruc-tion	Barriers/practical issues	Market impli-cations
												-term							
Maximum Demand control	✔	✔		✔		✔		✔	✔	✔	✔		✔		10 times a year?	typically 2 hours but could be longer	Instant	Unlikely to be popular	Change of culture if commonly used - electricity no longer always on - probably cause investment in alternative equipment. How do you decide what maximum demand level is appropriate?
Direct/Automatic load control	✔	✔	✔	Pick-up at end of period offsets dropped demand		✔	✔	✔	✔	✔	✔		✔	✔	10 times a year?	1-3 hrs (note - pickup problem at end of load control)	Instant (DNO switches off)	Lack of load in the UK that can be controlled (no central heating, no air conditioning). Needs equipment installed to turn off load selectively. H&S issues with turning off refrigeration for hours at a time.	Question of who decides when to load control - National Grid, DNO or supplier? When do they decide it is valuable?
Distributed/Back Up generation	✔	✔	✔			✔	✔		✔	✔			✔		Daily	Depends on gen type and local consent	Hours (start-up)	Not really DSM. Control systems have not yet been developed. Some distributed	Number of ongoing costs from managing and

	Problem Addressed	Led by:		Target Customers (see below for numerical breakdown)	Implementation Timeframe	Frequency and Duration (of interruption)	Notice period of instruc-tion	Barriers/practical issues	Market impli-cations
						s		generation is renewable and thus intermittent.	controlling a large amount of generatio