Evaluating The Business Case for Micro Demand Response and Energy Saving

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Executive Summary

Background

Interest in the potential for Demand Side Management (DSM) to create more reliable and sustainable energy systems has increased significantly over recent years, largely driven by International commitments to reduce greenhouse gas emissions. Greater participation from the demand side is seen as an important mechanism for addressing the issues of improving overall system balancing, reducing the reliance on inefficient fossil fuel generation, particularly at peak times and increasing the utilisation of renewable energy sources with variable output.

Households and Small and Medium Enterprises (SMEs) consume up to around 50% of electricity in developed countries. Therefore, encouraging these sectors to modify their energy consumption has the potential to make a significant impact on overall energy use. However, the participation of households and SMEs, which individually consume relatively small amounts of energy, requires that several thousand of ‘micro loads’ are influenced and co-ordinated to ensure that the desired outcome is achieved. Approaching consumers in order to integrate their energy use in this way is complex. Ensuring that consumers can take advantage of all available opportunities is an important component of ensuring the potential value of modifying consumer behaviour is maximised.

Therefore, a project was established to define demand response and energy saving products and to determine how they can be delivered into the residential and/or SME markets on a commercial basis, using energy saving service providers and/or demand Aggregator businesses. The project is entitled “Micro Demand Response and Energy Saving” and forms Task XIX of the International Energy Agency Implementing Agreement on Demand Side Management. Seven countries agreed to participate in Task XIX, namely Finland, France, Greece, India, the Netherlands, Spain and the United Kingdom.

Objectives

The overall objective of Task XIX is to evaluate the business case for micro demand response and energy saving products from the perspective of energy saving service providers and / or demand Aggregators.

Within the scope of this project energy saving and demand response products are defined as those intended to change the way energy is used whilst also achieving a commercial outcome for the business provider. Demand response products are those that target the delivery of short term changes in the pattern of electricity consumption for residential and SME consumers through the application of end-use monitoring and feedback (EUMF), time of use (ToU) pricing and remote / automatic switching of end-user loads.
Whilst the opportunities for effecting energy savings are wide and varied, the scope of Task XIX is limited, in this regard, to the opportunities available through the application of end-use monitoring and feedback.

Task XIX focuses on products targeted at residential and SME consumers. In the case of SME consumers, Task XIX considers individual sites with a maximum electrical demand of up to 100kW, regardless of the overall size of the business.

Approach

Whether or not micro demand response and energy saving products provide a commercially viable business proposition depends very much on individual circumstances. As such, it is not straightforward to make generic assessments on the commercial viability of a particular product or approach. Therefore, it was decided to use a number of country specific case studies to explore whether demand response and/or energy savings have the potential to provide a commercially viable business from the perspective of an Aggregator.

The following five case studies are considered, using a step by step approach:

Case Study 1: Dynamic control of electric heater loads for demand management, Finland

Case Study 2: Dynamic response of residential heating loads, France

Case Study 3: Energy efficient air-conditioning equipment, Greece

Case Study 4: Mass installation of energy efficient lighting, India

Case Study 5: Direct load control of commercial air conditioning, UK[1]

A step-by-step approach has been developed to enable the case studies to be methodically and rigorously analysed. The step by step process provides a useful basis upon which other case studies can be analysed.

Results

The benefits associated with demand response and energy savings vary between the case studies. From the perspective of the buyer (i.e. the organisation with a specific problem to be solved), the benefits include avoided peak power purchases worth up to €143/MWh (Case Studies 1, 2, and 4), avoided losses on sale of electricity at prices lower than the cost to supply (Case Study 3), and the avoided shortfall of reserve services (Case Study 5).

From the perspective of the consumer, the benefits include potential energy savings that could be realised if the consumer acts upon energy efficiency advice or responds to information provided via EUMF (Case Studies 2 and 5). Energy cost savings were specifically identified in two of the Case Studies (3 and 4), where the savings ranged from between €40/year and ~ €18/year, respectively. Whether such savings are sufficient to motivate consumers to participate is not explored within the scope of the project. However, the amount of money involved is considered to be relatively low, and therefore unlikely to provide a huge incentive to encourage customers to participate.

In a number of the case studies, the Aggregator is assumed to retain the income from the sale of demand response. In return, the consumer is rewarded via the provision of energy savings advice provided by the Aggregator. No attempt has been made to quantify the level of such savings, or more importantly, whether the 'promise' of such energy savings is sufficient to motivate consumers to participate. However, if the Aggregator is able to verify the level of energy savings that can be delivered, the possibility exists for the energy savings to earn White Certificates, which, when traded, could be used to provide additional incentives to the consumers.

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[1] The Case Study relates specifically to Great Britain, i.e. England, Wales and Scotland only, rather to the United Kingdom as a whole, which also includes Northern Ireland.

From the perspective of the Aggregator, the case studies demonstrate that whilst the development of demand response and energy saving products do offer the potential for a commercially viable business, this is very much predicated on the cost of the communication, monitoring and control technology.

Conclusions

This report concludes Task XIX of the IEA DSM Implementing Agreement and considers the business case for delivering micro demand response and energy saving products to domestic customers and small to medium enterprises. This report builds upon the first output of this Task, which evaluates the requirements and options for micro demand response and energy saving products.

This business case for demand response and energy saving products, particularly from the perspective of the Aggregator is evaluated using a rigorous step by step approach. By considering specific case studies, it has been possible to identify a specific problem to be solved, and hence identify the likely range of benefits that could be realised. However, there is a significant level of uncertainty surrounding the likely level of costs for the control, monitoring and communications technology required. Therefore, a range of technology costs have been considered, together with an analysis of the breakeven technology costs required to deliver a project with a zero NPV. The results of this analysis show that the benefits need to be at the upper end of the identified range. Thus, the role of 'future add-ins' becomes a critical element of the business case.

Interestingly, smart metering is not an integral component of the case studies considered within this study. In particular, where smart metering is in place, the Aggregator is assumed not to have direct access to the meter. Therefore, dedicated external communications and communication gateway are required to facilitate any demand response activity. The issue of access to the smart meters is one that needs careful consideration. Maximising the benefits of smart metering may require multiple organisation to access the meter, and the data obtained by the meter. However, consumers need to have confidence over the way that their energy data is used, as well as who accesses their data. This is particularly critical given the key role that smart meters could play in the deployment of demand response.

Glossary

BTU	British Thermal Units
CCS	Carbon Capture and Storage
CDM	Clean Development Mechanism
CEA	Central Electricity Authority *(in India)*
CER	Certified Emissions Reduction
CFL	Compact Fluorescent Lamp
CPP	Critical Peak Pricing
DNO	Distribution Network Operator
EUMF	End Use Monitoring and Feedback
LV	Low Voltage
NPV	Net Present Value
SME	Small and Medium Enterprise
STOR	Short Term Operating Reserve
TSO	Transmission System Operator
ToU	Time of Use

Contents

1 Introduction

Greater participation of the demand side is fast becoming regarded as an essential component of the suite of measures required to maintain electricity system balance. This is in an environment where Policy Makers are setting stringent targets for energy efficiency improvements and reduced CO_2 emissions, whilst the demand for energy, particularly electricity, is continuing to grow. Increased targets for the use of renewable generation, particularly wind, makes the task of maintaining the careful balance between the supply of and demand for electricity more challenging, particularly when accompanied with a move towards bigger and less flexible base-load generation plant, such as nuclear and plant with carbon capture and storage.

As a result, it is no longer considered feasible to consider only supply side solutions to the ever growing demand for electricity. Reducing and modifying the end-use demand for electricity can lead to reduced peak demand for electricity, reduced requirement for spinning reserve by fossil fuel fired generation and optimised utilisation of wind and other renewable generation sources.

Domestic consumers and Small and Medium Enterprises (SMEs) consume up to 50% of electricity in developed countries and, therefore, are important targets for the implementation of demand response and energy saving. However, in order to achieve the anticipated benefits it is necessary to influence and co-ordinate many thousands of micro loads, which is a complex process.

There are a number of mechanisms that can be employed to motivate small (i.e. domestic and SME) consumers to save energy and/or change their pattern of energy usage. These include;

- presenting to consumers a breakdown of their individual end-uses of energy, its cost and environmental impact, i.e. ***end use monitoring and feedback (EUMF)***;
- cost reflective charging for electricity consumption to reflect the higher costs incurred during peak periods or at other times of system stress, i.e. ***Time of Use (ToU) pricing***; and
- rewarding consumers for modifying their demand (or allowing their demand to be modified), so that the aggregated response can participate directly in the electricity market or offer balancing and reserve services to the system operator, i.e. ***incentive based demand response***.

These mechanisms represent business opportunities for energy saving service providers or demand Aggregators, in much the same way that Energy Service Companies have identified business opportunities associated with offering energy services to larger consumers.

This report is the second and final output of Task XIX - Micro Demand Response and Energy Savings, undertaken within the auspices of the IEA Implementing Agreement on DSM. This report builds upon the findings of the first output (from here-on referred to as Report 1) entitled Requirements and Options for Effective Delivery, published March 2010.

1.1 Aim, Scope and Objectives

The overall aim of Task XIX is to evaluate the business case for micro demand response and energy savings from the perspective of the Aggregator or energy savings service provider.

The scope of Task XIX is to investigate the implementation of ToU pricing, remote/automatic demand switching and energy end use monitoring for SME and residential customers so as to quantify the costs, benefits and business viability of such measures from the System Operator, demand balancing and energy saving perspectives. Within the scope of Task XIX, SME consumers are defined as individual sites with a maximum electricity demand of up to 100kW, regardless of the overall size of the business.

Specific objectives are to:-

- Define demand response and energy saving products to meet System Operator, Supplier, Government and Customer requirements;
- Identify, develop and define packages of demand and energy saving service products for residential and SME customers, based on EUMF, ToU pricing and demand control to meet the above requirements;
- Develop mechanisms to deliver demand response and energy saving service products;
- Evaluate how Aggregator businesses can provide demand response and energy saving service products for residential and SME customers;
- Develop Aggregator routes to market for residential and SME customers;
- Make an overall assessment of common ground and technologies to be shared with smart metering infrastructure;
- Estimate incremental costs of implementation of product delivery systems; and
- Quantify the business case for the provision of demand response and energy saving products.

1.2 Structure of the Report

The current document considers the business case for delivering micro demand response and energy saving products to domestic and SME consumers. It explores the costs and benefits associated with motivating consumer demand through the use of a number of country specific case studies. It is structured as follows:

- Section 2 describes the step by step approach used to evaluate different approaches to micro demand response and energy savings;
- Sections 3 to 7 present each of the case studies in detail, using the step by step approach described in Section 2;
- Section 8 discusses the results of the analyses presented in Sections 3 to 7, and compares the expected level of benefits for each case study from the perspective of the buyer, the consumer and the aggregator (where applicable). An analysis is also presented on the breakeven technology costs required to deliver a project with a zero Net Present Value to the aggregator;
- Section 9 presents the overall conclusions of the project, whilst Section 10 lists the recommendations arising from the findings of this study.

2 Approach

Whether or not micro demand response and energy saving products provide a commercially viable business proposition from the perspective of an Aggregator depends very much on individual circumstances. As such, it is not straightforward to make generic assessments on the commercial viability of a particular product or approach. Therefore, it was decided to use a number of country specific case studies to explore whether demand response or energy savings have the potential to provide a commercially viable business. Thus, the following five specific case studies are presented in Sections 3 to 7:

Case Study 1: Dynamic control of electric heater loads for demand management, Finland
Case Study 2: Dynamic response of residential heating loads, France
Case Study 3: Energy efficient air-conditioning equipment, Greece
Case Study 4: Mass installation of energy efficient lighting, India
Case Study 5: Direct load control of commercial air conditioning, UK[2]

In order to objectively identify whether or not energy saving and/or demand response have the potential to deliver a solution to a specific problem, a step-by-step approach was developed to define and evaluate each case study, and this Section describes that step by step process. Each of these steps, which are listed below, are described in Sections 2.1

Step 1 The Problem
Step 2 The Target Process
Step 3 The Control, Monitoring and Communications Technology
Step 4 The Business Case
Step 5 Future Add-ins (where applicable)

The business case is evaluated by means of discounted cash flow analyses. Specifically, a project with a positive Net Present Value over a defined timescale indicates that potential exists for a commercially viable business to be developed. In addition to evaluating the potential benefits, the discounted cash flow analysis requires a number of assumptions to be made, including;

- The discount rate to be applied;
- The costs of any control, monitoring and communications technology;

Section 2.2 provides an overview of the assumptions used in the case studies analyses.

2.1 Step by Step Approach

2.1.1 Step 1: The Problem

The first step in the implementation of demand response or energy saving programs requires the definition of the '*problem*' to be solved. This definition should include the identification of the '*buyer*' i.e. the organisation with a specific problem to be solved. The buyer is the organisation to whom an Aggregator will sell the demand response or energy saving services. In certain cases the Aggregator will be the buyer.

[2] Case Study 5 relates specifically to Great Britain, i.e. England, Wales and Scotland only, rather to the United Kingdom as a whole, which also includes Northern Ireland.

2.1.2 Step 2: The Target Process

The target process is the specific end use of electricity that is able to deliver the demand response or energy savings required to solve the problem identified in Step 1. Here, the '*provider*' is defined as the organisation with the target process, and within the scope of this project includes households and SMEs.

Definitions of the various types of load and their suitability for different types of demand response programs can be found in the first Task XIX report[3] .

2.1.3 Step 3: The Control, Monitoring and Communications Technology

Once the problem and the target process have been identified, it is possible to define the control, monitoring and communications technologies required.

The control, monitoring and communications technologies are likely to be specific to the particular requirements of each individual demand response or energy saving product.

The first Task XIX report[4] provides a description of the minimum requirements of the different technical architecture components for a range of different products.

2.1.4 Step 4: The Business Case

For a demand response or energy saving product or service to become successful it must:

- Make savings for the 'buyer'
- Produce a net income for the 'provider'
- Make money for the Aggregator.

The Business Case therefore explores the costs and benefits to each of the participants (or stakeholders), with the aim of demonstrating a win – win – win situation. For example, in the case of peak price avoidance through households avoiding use at peak times:

- The 'buyer' must make a saving compared to the alternatives of either buying high priced energy or investing in more capacity;
- The 'provider' – e.g. the householders – must benefit through lower bills or improved service;
- The 'Aggregator' must generate a new, positive, income stream

2.1.5 Step 5: Future Add-ins

Often the installation of improved control, monitoring and communication equipment will open up other possible income streams for the Aggregator, thereby providing additional benefits to the 'providers'. Exploring all of the possible products and services (and all possible 'buyers'), arising from a single initiative, may turn a marginal Business Case into a highly viable one, either now or in the future.

For example, the installation of a Building Monitoring System (BMS) to provide energy savings (cost savings to the host SME, energy purchase cost savings to the Energy Supplier), may facilitate the provision of, say, Reserve Services for the Transmission System Operator (TSO).

3 Table 6.1 - Requirements and Options for Effective Delivery, March 2010, Task XIX of the IEA DSM Programme
4 Section 8- Requirements and Options for Effective Delivery, March 2010, Task XIX of the IEA DSM Programme

2.2 General Assumptions

As mentioned previously, a discounted cash flow analysis has been used to establish whether a viable business case exists. Specifically, a project with a positive Net Present Value over a defined timescales indicates that potential exists for a business to be developed. In addition to evaluating the potential benefits, the discounted cash flow analysis requires a number of assumptions to be made, including;

- The discount rate to be applied;
- The costs of any control, monitoring and communications technology;

Discount rate

The discount rate, sometimes referred to as the hurdle rate or the opportunity cost, is the return foregone by investing in the project rather than elsewhere. The discount rate is generally the appropriate weighted average cost of capital, which comprises the following two factors:

- The time value of money, i.e. the risk free rate; and
- A risk premium.

Short dated government bonds are usually used as the benchmark for the rate of return for an investment with zero risk. However, the risk premium reflects the extra return needed to compensate for any risks associated with the investment (i.e. the risk that the future cashflows may not materialise). Thus, the appropriate discount rate to apply is very much a matter of personal judgement. Here, discount rates of 7.5% or 15% were applied in the case studies presented in Sections 3 to 7, as shown in Table 2.1 below.

Table 2.1 Discount rates applied in case studies

	Case Study	Discount rate applied	
1	Dynamic control of electric heater loads, Finland	7.5%	Case Study 1: Section 3
2	Dynamic response of residential heating loads, France	7.5%	Case Study 2: Section 0
3	Energy efficient air-conditioning equipment, Greece	7.5%	Case Study 3: Section 5
4	Mass installation of energy efficient lighting, India	15%	Case Study 4: Section 6
5	Direct load control of commercial air-conditioning, UK	7.5%	Case Study 5: Section 7

Technology Costs

Whilst a degree of uncertainty surrounds the appropriate discount rate to apply, it is considered here that the level of uncertainty over technology costs has a greater impact on the business viability of aggregating small customer loads. The results presented in

Sections 3 to 7 show that the business viability is highly dependent upon the level of technology costs. In the case studies requiring control, monitoring and communications technology, no proprietary technology exists. Thus it is difficult to ascertain an appropriate level of investment required. Therefore, the case studies consider a range of technology costs, as shown in Table 2.2.

Table 2.2 Summary of Case Studies

	Case Study	**Consumer Segment**	**Control, Monitor, Communication Technology Costs**	
			Upfront (per customer)	**On-going (per year per customer)**
1	Dynamic control of electric heater loads, Finland	Residential	€50 to €300	€5 to €30
2	Dynamic response of residential heating loads, France	Residential	€50 to €300	€5 to €30
3	Energy efficient air-conditioning equipment, Greece	Residential / SME	n/a	n/a
4	Mass installation of energy efficient lighting, India	Residential	n/a	n/a
5	Direct load control of commercial air-conditioning, UK	SME	£50 to £300	£5 to £30

Appendix I provides some example technology costs for commercially available home automation products, as well as typical costs associated with smart meter deployment. These costs provide a useful benchmark for the case studies, and would suggest that an appropriate range of technology costs have been considered.

3 Case Study 1: Dynamic control of electric heater loads for demand management, Finland

Step 1 - The Problem

Fixed (or static) Time of Use tariffs are well established in Finland, and as a result, electricity market prices no longer follow the off-peak / on-peak pattern applied to these tariffs. There is no longer a clear difference between the cost of electricity during the night and the day. For most of the time, electricity spot prices are relatively low and rather constant, as shown in Figure 3.1, which shows the spot prices over the period 16 to 22 January 2010. These prices represent the amount paid by Suppliers for electricity purchases via the spot market. As a result of the flattening of spot market prices, there is also very little variation between the day and night rate for customers on a fixed Time of Use (ToU) tariff. For example, typical charges for units consumed in the day are around 11.5c/kWh compared to around 8.8c/kWh during the night[5].

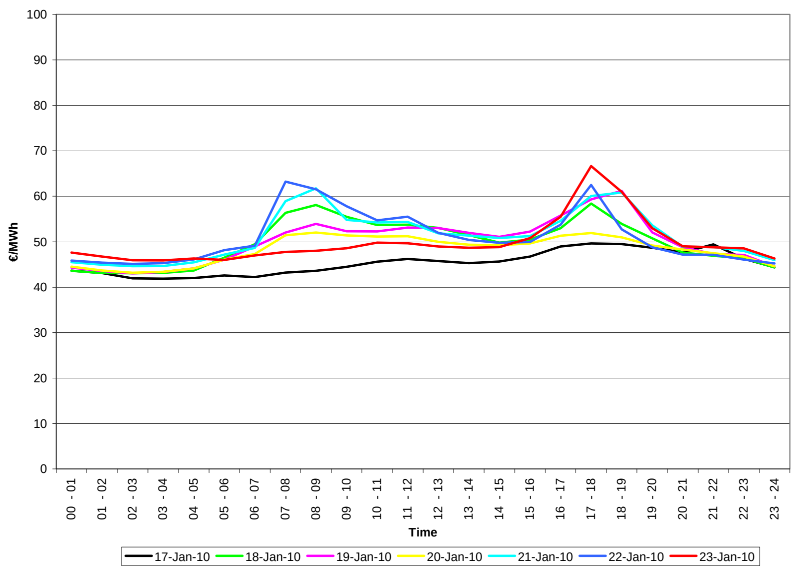

Figure 3.1 Spot prices in Finland, 17th to 23rd January 2010

However, price peaks are becoming higher and more frequent. Examples of such peaks are illustrated in Figure 3.2, which shows spot prices of €1000 to €1400/MWh on a selection of days during January and February 2010, compared to prices of around €40 to 60/MWh over the week 17 to 23 January 2010 (as shown in Figure 3.1).

5 These unit prices represent the total price (i.e. the energy price and the distribution charge).

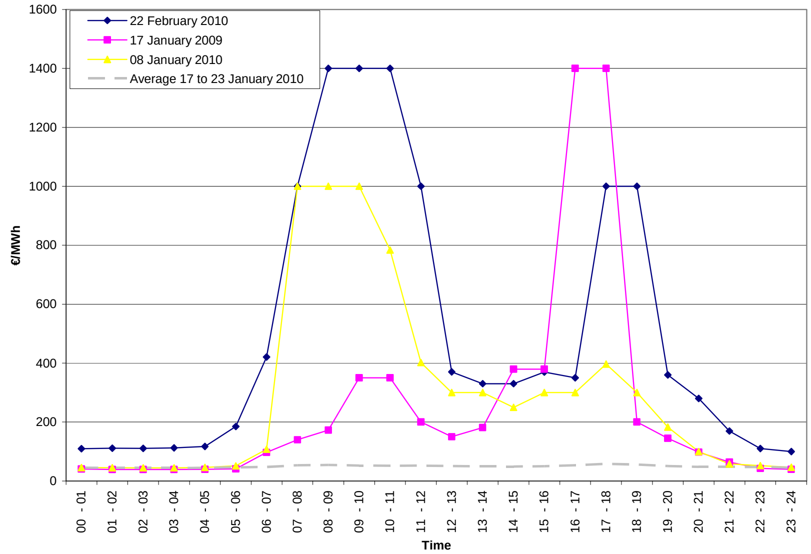

Figure 3.2 High spot prices in Finland, 8th January 2010

In addition, there have even been a number of occasions over recent years when price peaks have occurred during the 'off-peak' period. One such example is shown in Figure 3.3, which shows the variation in spot prices incurred over a seven day period in January 2006. Such instances create a disjoint between the prices paid by consumers on static ToU tariffs and the spot market price paid by Suppliers.

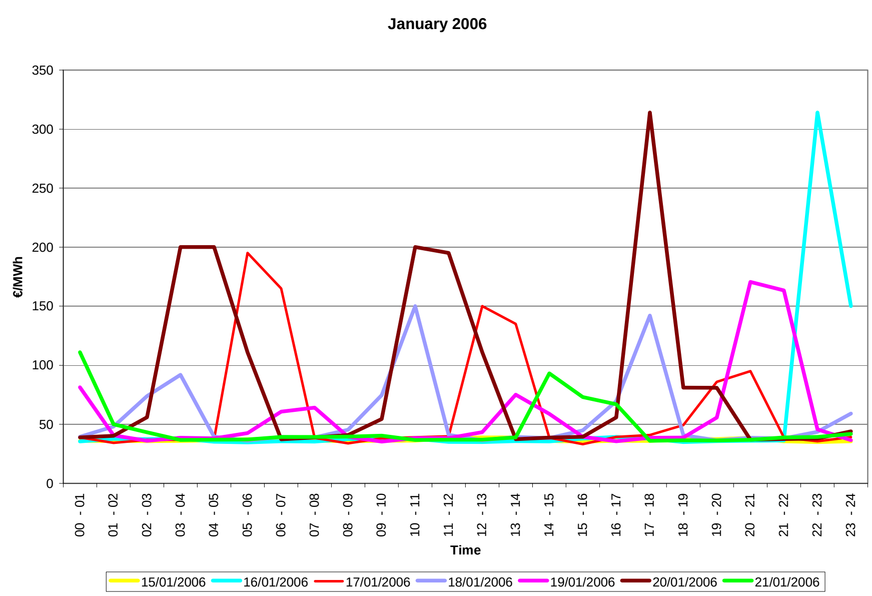

Figure 3.3 Example of High Spot Prices in Finland during off-peak period 15th to 21st January 2006

With electricity peaks expected to occur more frequently and become more pronounced[6], there is a need to better manage demand for electricity. By so doing, Energy Suppliers have the potential to make significant cost savings by avoiding the purchase of electricity during the peak periods.

Step 2 - Target process:
As highlighted in the first Task XIX report[7], approximately one quarter of households in Finland utilise some form of electric heating, which accounts for around 40% of all electricity consumed by the household sector. Electrical heating is used for space heating of homes and vacation houses (including full storage heating, partial storage heating and direct heating) as well as for domestic hot water, car heating and for electrical saunas, which are found in many homes in Finland. Static ToU tariffs are well established, such that on very cold winter days, about 1GW[8] of load is shifted to the 'off-peak' period, a significant proportion of which is attributable to domestic heating loads. However, dynamic and variable market price patterns, such as occasional large price variations and the increasing occurrence of high prices during the low price ToU periods, means that ToU prices are no longer providing the appropriate pricing signals to consumers. As such, there is increasing interest in replacing the existing ToU heating controls with more dynamic control methods.

It is also worth noting that it is compulsory for electrically heated households in Finland to have some form of reserve heating, such as a heat storing fireplace (typically a woodburning stove surrounded by stone that stores the heat and releases it slowly over time[9]) Thus, households have some flexibility to use fuel switching as a means of avoiding high priced periods during the day. However, heat pumps (particularly air to air heat pumps) are becoming increasingly popular as an additional form of heating which, although reducing overall energy consumption, do not reduce the peak load. Rather, the peak load is increased as other forms of non-electrical heating are replaced by the heap pump.

The results in Table 3.1, undertaken as part of ongoing research in Finland highlight the typical annual benefits achieved through the application of different pricing schedules and control methods. The results obtained using simple models for the dynamic heat balance of buildings[10], and using historic spot prices, show the benefits that could be achieved by determining the optimum response to variations in the spot price as compared to the existing ToU controls. These benefits represent the total benefits available, which would need to be distributed amongst all relevant stakeholders (i.e. the consumer, the Aggregator and the Retail Supplier).

Table 3.1 Typical Annual Benefits of Application of Spot Price Based Control for a Household in Finland

	Annual benefits (€/customer/year)	
	Typical house with full storage heating	Apartment with partial storage heating
Normal year*	40	50
Year with high peaks**	40 to 65	80 to 100

(*) For years around the year with high peak prices.
(**) Results relate to the year summer 2005 to summer 2006. Although the analysis has not been repeated using data for 2009 to 2010, it is anticipated that the results would be of a similar magnitude.

6 Paper 0508 Experiences from spot-market based price response of residential customers, Pekka Koponen, Seppo, Karkkainen, VTT, CIRED 2007
7 Requirements and Options for Effective Delivery, March 2010, Task XIX of the IEA DSM Programme
8 Demand Response in Finland, Pekka Kopponen, presentation at Workshop on Demand Response in Europe: Status, Barriers, Oppourtunities and Outlooks, 3 – 4 March 2010, Ispra, Italy
9 See www.woodmasonry.com/pages/whatis.html for an example of such a system
10 Project MAHIS (partial storage heating) and ENETE (full storage heating)

It is interesting to note that the savings in an apartment with partial storage heating (typically referred to as a row house apartment in Finland) are estimated to be greater than in a house with an overall higher demand for heating, but with full storage heating. It is thought that this is attributable to the fact that when the weather is very cold, a house with limited storage capacity uses some electric heating during the evening when high prices are most likely to occur. The above estimates assume that this new demand response does not lead to any reduction in the price peaks. In practice, however, even rather small volumes of demand response could lead to a significant reduction in the magnitude of any peaks. This somewhat reduces the benefits to the responsive loads, but does lead to overall benefits to all non-responsive consumers and Retail Suppliers.

Nearly all the benefits for a full storage heating house can be achieved without changing the internal systems and wiring of the house. However, only a fraction of the full potential for a house with partial storage heating can be achieved without improved home automation.

Step 3 - Control, monitoring and communications technology:

Controller

It is envisaged that a heuristic controller would be required to enable dynamic control of full storage heating systems. The controller would therefore determine the appropriate charging cycle for the storage heaters based on internal and external temperatures and on the day ahead spot prices. Heating systems with partial storage heating would require some form of optimisation to 'fine-tune' the balance of direct and storage heating utilised by the house, according to the internal and external temperatures and the variation in spot prices.

Response Monitor

The existing ToU metering and settlement arrangements are not suitable for dynamically controlled loads, therefore hourly metering and settlement is required. All residential consumers will have hourly metering and settlement from 1 January 2014, although the transition will occur much sooner for some consumers. Therefore, the business case evaluation assumes that the cost of the hourly metering and settlement is met as part of the existing roll-out program.

Internal Communication

The two options for internal communication are as follows:

- The ToU control is used to switch the relays controlling the power to groups of heaters within the home. This is by far the most common approach utilised.
- A home automation network controls the set-points of individual thermostats located around the home.

Whilst the second option is considered to be a better approach due to the improved capability to match heat output to specific heating requirements, the first option requires no (or minimal) additional investment. As such, the business case evaluation assumes that minimal additional investment in internal communications is required.

External Communication

The smart metering system is used to collect the metered data and distribute non time critical load control signals[11]. In the case of implementing the dynamic control of residential storage heating for the sole purpose of avoiding peak prices, the only requirement is to be

11 The new metering systems are required to be able to transfer at least one load control signal to the customer

able to transmit information on the price of electricity. In this case, day ahead spot prices are available soon after clearing has been completed (around 13 o'clock on the day ahead). In Finland, metering is the responsibility of the Distribution Network Operator (DNO). Therefore, Retail Suppliers and/or Aggregators do not have the opportunity to communicate directly with the meter. Therefore, the Supplier will incur additional costs to transmit spot prices to consumers at the day ahead stage.

However, if the option of utilising the heating load to provide reserve and/or system balancing services to the TSO is to be incorporated into the business case (possibly as a future add-in), there would be a requirement to implement a more sophisticated communication system to enable communication signals to be transmitted over the much shorter timescales required by these services[12].

Communication Gateway

As mentioned previously, metering is the responsibility of the DNO. Therefore, Retail Suppliers and/or Aggregators do not have the opportunity to communicate directly with the meter. As such, the smart meter cannot provide the gateway between any internal and external communications. Therefore, a dedicated communications gateway would be required, which could form an integral part of the controller.

Step 4 - Business Case

As stated in Step 1, the problem to be addressed is the avoidance of peak prices. In particular, because Supply is essentially a low margin high volume business, the profit of a Energy Supplier is very sensitive to market price peaks.

Therefore, the Business case looks to create a win/win/win situation for:

- The Energy Supplier
- The Householders
- An Aggregator or energy saving service provider (where applicable)

There are a number of approaches that could be implemented to deliver the dynamic control of residential storage heating. These might include

- Consumer led approach - i.e. the consumer invests in the required control technology
- Supplier led approach – i.e. the Energy Supplier purchases the technology and provides it to consumers at low or zero cost.
- Aggregator led approach – i.e. an Aggregator purchases and installs the technology required, and sells the required demand response to the Supplier.

In all cases, the benefits of the improved dynamic control of the storage heating load is the same. However, the way that the benefits are shared differs in each case, as described in the following sub-sections. In all cases, it is assumed that investment is only required in control, monitoring and communication technology (as described in Step 2), and no investment is required in the heating system itself.

12 Section 8 - Requirements and Options for Effective Delivery, March 2010, Task XIX of the IEA DSM Programme

Customer Led Approach

With this approach, the household invests in the control technology required to control the charging cycle of their storage heaters according to the prevailing spot prices.

Spot price based tariffs are already offered to consumers in Finland. Although this means that the customer faces all the price risks, they are also able to accrue all of the benefit associated with dynamic demand control. In particular, the strong competition in the Finnish retail market means that Suppliers are effectively required to pass the benefits to the consumer by keeping the margin on spot price based tariffs very low. Hedging the price risks with financial instruments is so expensive to Suppliers that it becomes profitable to offer spot price tariffs that, over the long term, are cheaper to the consumers than fixed tariffs.

Thus, the Supplier benefits because they are no longer exposed to the price peaks and also from any reduction in market prices that arise due to any increased demand response.

The net benefit from the perspective of the householder then depends upon the actual annual benefits that can be achieved and the level of investment required.

With considerable uncertainty over both the investment required and the likely level of annual benefits, it is therefore useful to consider a discounted cash flow analysis for a number of different scenarios. As such, the following range of technology costs and annual benefits considered are summarised below in Table 3.2 and Table 3.3 below.

Table 3.2 Range of Control, Monitoring and Communications Technology Costs in Finnish Case Study

	Scenario			
	(1)	(2)	(3)	(4)
Up-front (€/customer)	50	100	150	200
On-going (€/customer/year)	5	10	15	20

Table 3.3 Range of Annual Benefits in Finnish Case Study Consumer Based Solution

	Scenario		
	(A)	(B)	(C)
Annual Benefit (€/customer/year)	40	70	100

Figure 3.4 below therefore shows how the Net Present Value (NPV) to the Consumer varies with technology costs and annual benefit. The results show that over a 10 year period, and assuming a discount rate of 7.5%, there is a net benefit to the consumer when the annual benefit is as low as €40 per year, provided that the technology costs are not at the upper limit of the range considered (i.e. €200 upfront, €20/year ongoing). For example, with an annual benefit of €40/year, and upfront technology costs of €150 with the associated ongoing cost of €15/year, the NPV to the consumer is €22 over the 10 years. As 'off the shelf' technology solutions currently exist, the technology costs are more likely to be at the upper range, particularly over the short term. Therefore, assuming technology costs of €200 upfront, €20/year ongoing, an annual benefit of €70/year would lead to an overall NPV of €143/year. This increases to €349/year for an annual benefit of €100/year.

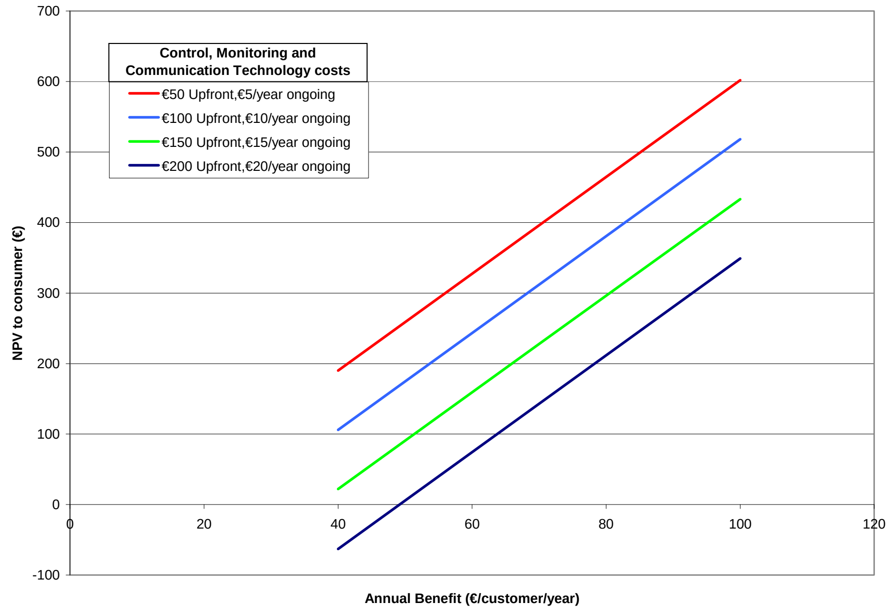

Figure 3.4 Potential NPV to Consumer of Investment in New Technology to Enable Dynamic Management of Space Heating

Supplier Led Approach

The profit of a Retail Supplier is very sensitive to market price peaks, because of the high-volume, low-margin nature of the business. Therefore this approach considers the case for aggregated spot price control by a Supplier as a means of minimising price risks.

In this case, the investment in the control, monitoring and communications technology is made by the Supplier, and the benefits are then shared between the Supplier and the Consumer. It is not permitted for Suppliers to 'tie-in' the customers, therefore Suppliers risk the stranding of their investments if consumers subsequently switch to an alternative Energy Supplier. Therefore, it would seem reasonable to suggest that the Supplier would expect to retain the majority of the benefit, with only a modest proportion passing to the consumer. In this case, it is assumed that the Supplier retains 90% of the annual benefits.

In addition, an allowance is included to reflect customer churn, whereby a proportion of customers (in this case 2% per annum) move to another Energy Supplier. Thus, over a 10 year period, if 2% of customers are lost per year and replaced with customers without dynamic demand management, the annual benefit also reduces by 2% per year.

Therefore, presenting the results on a per thousand customer basis, the annual benefits to the Supplier in Year 1 and in Year 10 are as summarised in Table 3.4.

Table 3.4 Range of Annual Benefits in Finnish Case Study
Supplier Based Solution

	Scenario					
	Year 1			Year 10		
	(A)	(B)	(C)	(A)	(B)	(C)
(€/year/customer)	40	70	100	40	70	100
Number of customers	1,000	1,000	1,000	834	834	834
(€/year)						
Total Benefit	40,000	70,000	100,000	33,360	58,380	83,400
Amount for Supplier	36,000	63,000	90,000	30,024	52,542	75,060
Amount for Consumers	4,000	7,000	10,000	3,336	5,838	8,340

Figure 3.5 therefore shows the net benefit (or disbenefit) to the Energy Supplier for the range of technology costs considered under the customer led approach (see Table 3.2). As indicated in Table 3.4, the savings under the Supplier led approach are now shared between two parties, albeit with the Supplier taking the majority of the savings. Therefore, as would be expected, the net benefits to the Supplier are less than those accruing to the Consumer in the earlier example.

Consequently, a total annual benefit per customer of €40/year, and technology costs of €150/customer upfront and €15/year/customer ongoing, the NPV to the Supplier is now negative (equivalent to -€17/customer) over the 10 years. For a consumer led approach, the equivalent benefit to a consumer for the same annual benefit and technology costs is €22.

It would seem reasonable to suggest that the technology costs for an Energy Supplier would be less than those incurred by Consumers due to economies of scale. Thus, at technology costs of €150 upfront and €15/year ongoing, the Supplier would require total annual benefits of around €104 /year/customer for the investment to be worth €349/customer, i.e. the level of benefit considered in the earlier example.

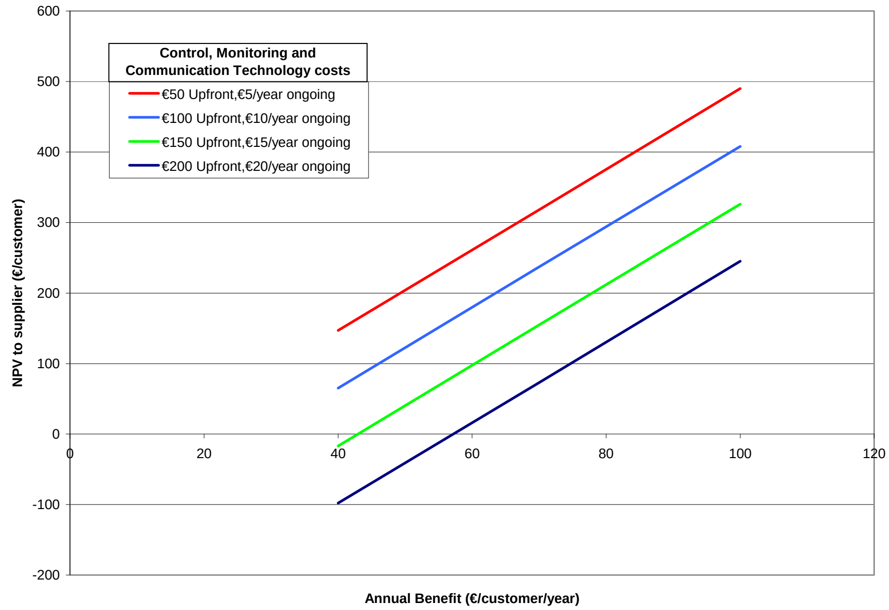

Figure 3.5 Potential NPV to Energy Supplier of Investment in New Technology to Enable Dynamic Management of Space Heating

Aggregator Led Approach

In this case, the investment is made by a third party Aggregator, who then sells demand response to the Energy Supplier. As such, the benefits now need to be shared three-ways, i.e. between the consumer, the Energy Supplier and the Aggregator. Consideration of the benefits arising from a Supplier led scenario highlight that such an approach is unlikely to present a viable business opportunity for the Aggregator. Therefore, in this approach it is assumed that the Aggregator also offers additional demand response services to the TSO, as indicated by the schematic shown in Figure 3.6.

The design of the distribution in networks is already sufficiently robust to deal with the impacts of the existing ToU tariffs, and as such it is considered that there is no business case from avoided or deferred distribution network reinforcement; although this could change in the future if there is a significant growth in distributed generation. However, this is considered unlikely in the short to medium term as feed-in-tariffs for renewables will not be available for small scale generation. Therefore, in the schematic shown in Figure 3.6, the opportunity to sell services to a DNO is shown in grey type, indicating a potential future add-in for the Aggregator.

Here, the analysis assumes that all the income from the provision of demand response services is retained by the Aggregator. In return for participating, the householders are rewarded through the provision of targeted energy savings advice.

For this analysis, the comparison is made between a Supplier purchasing electricity from a new peaking power generator or alternatively, purchasing demand response from the Aggregator. In practice, the trades would be undertaken via the spot market rather than bilaterally as shown here.

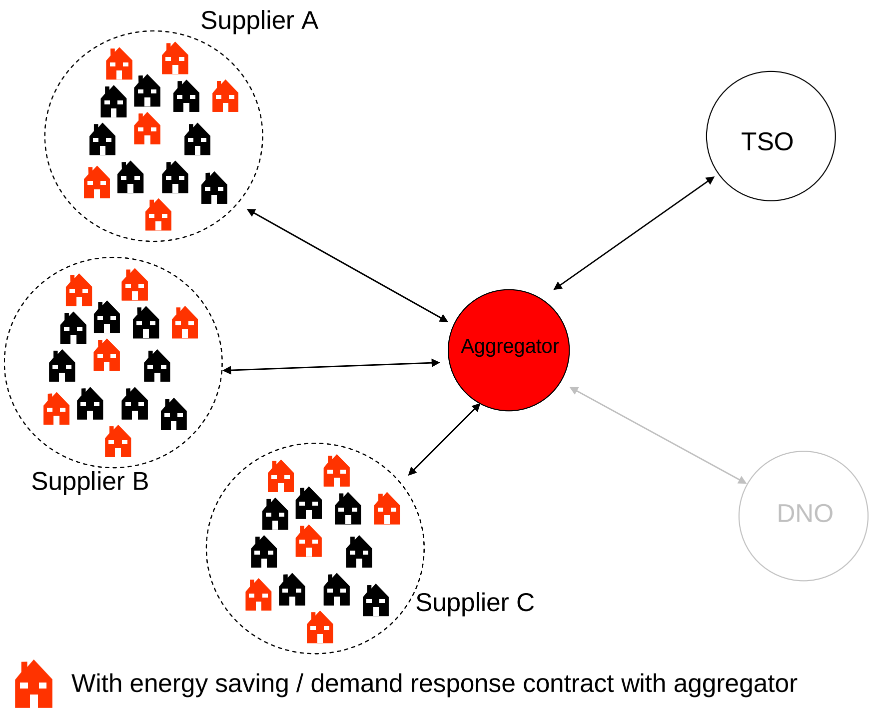

Figure 3.6 Demand Aggregation Approach

Each of the Suppliers shown in Figure 3.6 is required to buy sufficient electricity to meet the needs of its consumers in each trading period. As mentioned previously, purchases made via the day ahead spot market are susceptible to high peak prices. Therefore, in this example, rather than purchasing power at the peak prices from the spot market (Option 1), the Supplier instead purchases demand response from an Aggregator (Option 2).

Thus, for Option 1, it is assumed that the Supplier purchases electricity from a new 1MW generator designed to operate during peak price periods only. It is assumed that the generator operates with a load factor of 5%, i.e. runs for 438 hours per year, producing 438MWh of electricity. Therefore, based on the costs associated with investing in new peaking generation plant as summarised in Table 3.5, the cost per unit of electricity would need to be €168/MWh for the generator to breakeven over 20 years, assuming a discount rate of 7.5%. Although considerably higher than typical spot prices, see Figure 3.1, it is still lower than the very high peak prices that have been experienced.

Table 3.5 Costs of new peaking generation[13]

	Benchmark (*)	
Capital cost	$634/kW	€476.69/kW
Staff / maintenance costs	$10.53/kW	€7.52/kWh
Fuel costs	$3.17/kWh	€2.38/kW

* Based on an exchange rate of 1US$ = €1.33

With Option 2, the Aggregator invests in appropriate technology to allow the heating load of residential consumers to be controlled such that the Supplier now purchases an equivalent level of demand response rather than generation output.

[13] Further examples of costs of generation can be found in Appendix 2

Assuming technology costs of €150/customer up-front and, €15/customer/year on an ongoing basis, the cost per unit of demand response would need to be €84/MWh for the Aggregator to breakeven over 20 years. Thus, the benefit to the Supplier of purchasing demand response rather than the output of peaking generation plant is equivalent to a saving of €84/MWh for the 438MWh units considered. This equates to a total annual saving of €36,792, which is slightly less than the lower level of annual benefits reported in Table 3.1, i.e. €37/customer/year here compared to €40/customer/year in Table 3.1. This would suggest that, although the analysis here has adopted a rather simplistic approach, the results provide a reasonable assessment of the benefits of demand response.

Step 5 –Future Add-ins

A future add-in could be the provision of balancing services to the TSO. Here, a simplistic approach is adopted, whereby it is assumed that the Aggregator provides reserve services for 400 hours per year, and earns $200/MWh by so doing[14]. However, as discussed under Step 2, Target Process, more sophisticated communications will be required to ensure the demand response can be delivered within the timescales required. In this case, it is assumed that the technology costs are doubled to €300/customer upfront and €30/customer/year on an ongoing basis. Thus, incorporating the additional investment in order to facilitate the provision of reserve services would provide a NPV to the Aggregator of €497/customer, or approximately €0.5m per 1,000 customers over 20 years.

[14] Broadly equivalent to the level of payment made for reserve services in the UK, See Section 7

4 Case Study 2: Dynamic response of residential heating loads, France

Step 1 - The Problem
In France, peak loads that occur for around 10 hours per year typically result in energy prices of around €1,000/MWh[15]. For example, electricity market prices reached €1,000/MWh for 7 hours in 2003, for 4 hours in 2007 and 4 hours in 2009. Such events are expected to occur more often in the coming years. With peak demand growing faster than the energy consumption, there is interest in encouraging micro demand response as an alternative to using peaking power plant at the time of these peak demands. However, with opportunity to participate limited to only around 10 hours per year, it is difficult to justify the capital investment required to implement such demand response.

The Balancing Mechanism enables RTE (The Transmission System Operator in France) to utilise available reserves to maintain the balance between generation and consumption in real time, solve network constraints and determine the reference price for the settlement of imbalances of Balance Responsible Entities. Whilst generators are obliged to offer any surplus generation capacity on the balancing mechanism, the process is voluntary for consumers. To date, participation from consumers has been limited[16].

The French Government has set up two working groups to focus on encouraging greater participation from the demand side. The first of these working groups is looking at the options for remunerating micro demand response for peak load management. The second working group is investigating options for encouraging greater participation in the Balancing Mechanism.

Step 2 - Target process
Direct electric heating represents a significant energy end use in France, accounting for around 30% of the electricity used by households. Direct heating loads also coincide with system peak demands which typically occur in the early evening during cold winter periods.

Figure 4.1 represents the French load curve during an example Winter day, as determined by the French TSO (RTE). As can be observed, the heating load is reasonably constant within a day, but its level depends on the prevailing weather. In order to integrate the effects of variations in the weather during Winter, the heating load profile has been estimated over a normal heating season using the load profiles used by ERDF (the distribution network operator in France) for energy settlement purposes. As these profile are related to the types of regulated supply contracts (base or peak/off-peak tariffs) – and non directly to the types of heating systems – it has been assumed that households with electrical heating subscribe to regulated peak-off-peak tariffs.

Under this assumption, Figure 4.2 shows the average load profile of French households with electrical heating system on a typical winter weekday. The profile does not represent the 'actual' profile of a typical household, but the average across a large sample of households, adjusted according to weather and day-type. As there are several peak/off-peak schedules in France, the profile hereafter is the result of the superposition of several load profiles according the localisation of the sampled households. The lighting, water heating and other base loads were estimated by comparison of the load profile during the winter and summer, thus providing an estimate of the contribution to the load profile made by heating during the winter.

15 Powernext
16 An experimental call for tender was issued in 2008, which resulted in participation by six large industrial consumers.

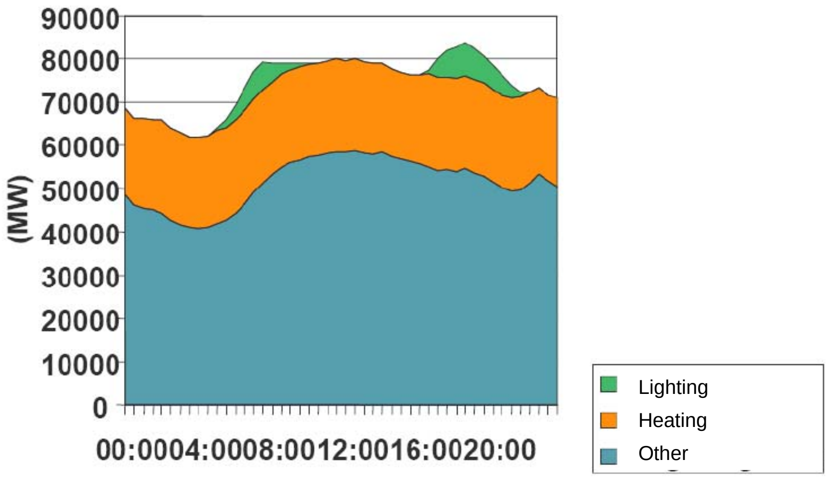

Figure 4.1: French load curve during Winter

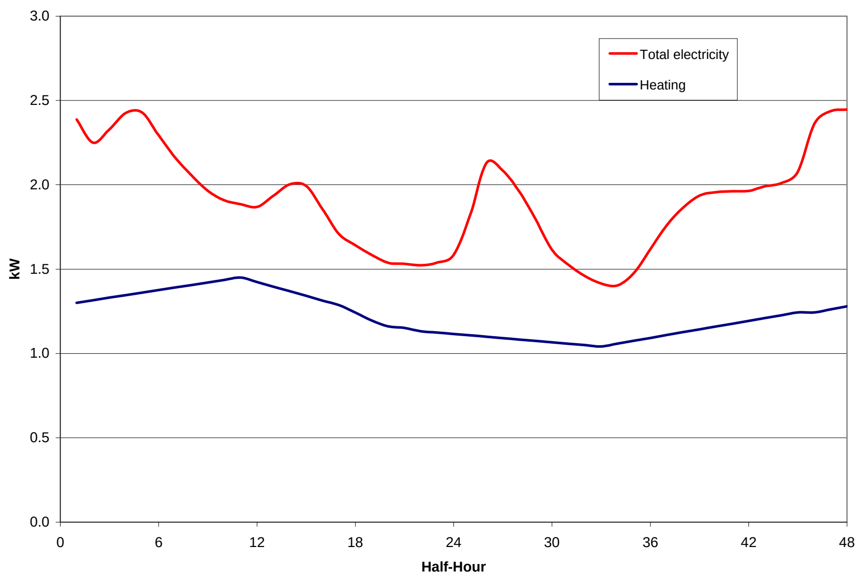

Figure 4.2 Average load profile of electrically heated households in France

Step 3 - Control, Monitoring and Communications Technology

The electrical heaters can be disconnected with electric relays, using an arrangement indicated in Figure 4.3. Such an arrangement enables residential heating loads to be remotely controlled so that the aggregated demand response can be offered into the Balancing Mechanism.

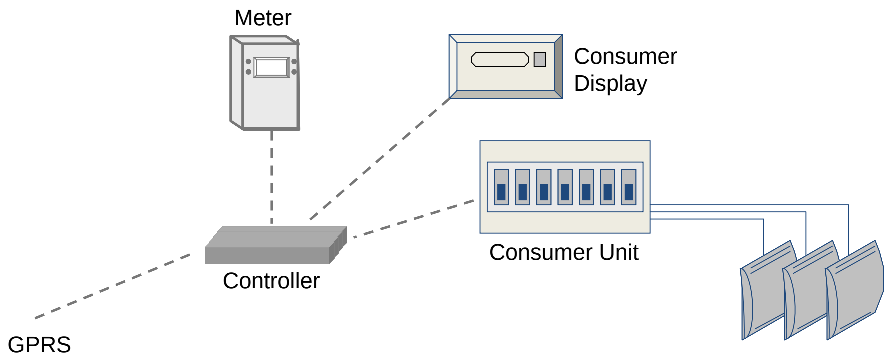

Figure 4.3 Control, Monitoring and Communications Technology

Table 4.1 provides a brief description of the technical components shown in Figure 4.3.

Table 4.1 Technical Architecture Components for heating load management in households, France

Component	Description
Controller	The controller connects to the consumer unit and controls the supply to the individual heaters within the household.
Response Monitor	Existing non half-hourly metering
Internal Communication	Option for wired or wireless connection between the controller and the consumer unit
External Communication	The signal to disconnect heater loads is sent via GPRS to the controller.
Communications Gateway	The gateway could be an integral part of the controller.

Step 4 - Business Case
As highlighted in Report 1, most householders in France (approximately 98%) are supplied by the incumbent energy supplier EDF[17]. Therefore, the role of the Aggregator is assumed to be as shown in Figure 4.4.

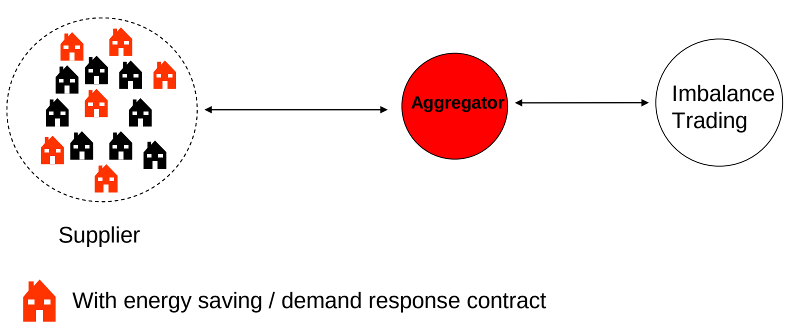

Figure 4.4 Demand Aggregation Approach
Dynamic response of residential heating loads, France

[17] Table A1.12, Appendix 1, Requirements and Options for Effective Delivery, March 2010, Task XIX of the IEA DSM Programme

As discussed in Step 1, the problem to be addressed is the lack of participation by the demand side in the balancing mechanism, which is organised by RTE the Transmission System Operator. Therefore, the business case seeks to evaluate whether aggregating residential heating loads has the potential to offer benefits to:

- the TSO, who is responsible for managing and organising the balancing mechanism;
- the Householders, who provide the demand response resource; and
- the Aggregator, who is responsible for participating in the balancing mechanism.

Such demand response also has the potential to offer specific benefits to Distribution Network Operators, via avoided or deferred network reinforcement, and Suppliers, via avoided peak purchasing. However, only the benefits to the TSO, the householders and the Aggregator are explored here.

The benefit to the TSO is the ability to purchase lower cost downward balancing actions from the demand side rather than more expensive upward balancing actions from a peaking power plant.

Figure 4.5 below shows the maximum daily imbalance prices in 2009. These prices represent the amount that would be paid to Balancing Responsible parties that help to reduce the overall imbalance of the system. Thus, if a Balancing Responsible Party consumes less energy than they have purchased at a time when the overall system is short, they will be paid the imbalance price for that 'shortfall'. The imbalance price is a weighted average of all upward and downward balancing offers accepted by the TSO to maintain the system in balance. Thus, the price paid to individuals can be higher or lower than the average weighted values show in Figure 4.5.

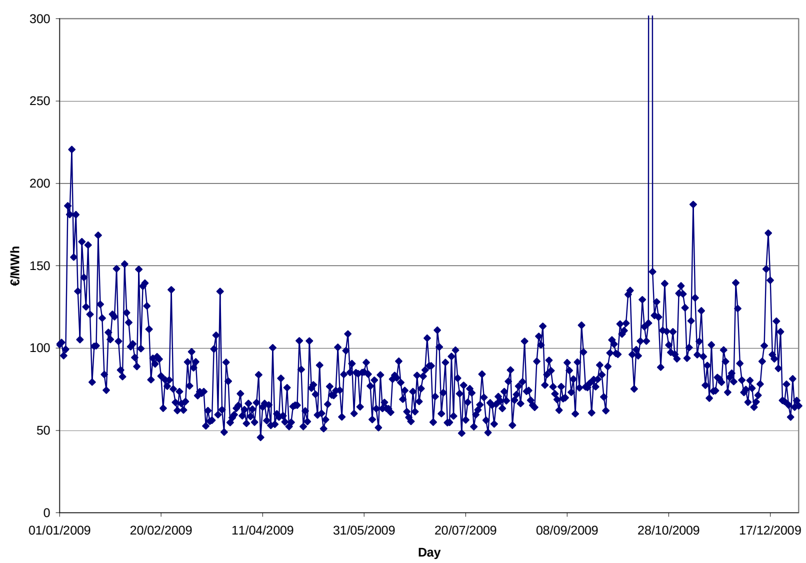

Figure 4.5 Maximum Daily Imbalance Prices, 2009

The spike shown in Figure 4.5 during October represents a single, exceptional event when the imbalance price was €2,948 for a single half-hour. On Monday 19th October, the electricity were exceptionally high on the balancing mechanism and on the electricity market (Powernext). The French energy regulatory authority (Commission de Régulation de l'Energie) led an investigation to determine the origins of the event and concluded that the peak price was due to a combination of:

- a revision of the consumption forecasts between Friday and Sunday for the Monday due to exceptions cold weather, equivalent to a forecast increase in demand of 3000MW; and
- a revision of the production forecast (availability of power plants) between Friday and Sunday due to some failures in a nuclear and a hydro plant over the weekend – equivalent to a reduced availability of 4100MW.

The events combined to an imbalance of 7100MW, which led to the exceptional prices.

Assuming that demand response is able to earn, as a minimum, a price equivalent to the average shown in Figure 4.5, then the income that could be earned through participation in the balancing mechanism varies between approximately €8/customer/year and €23/customer/year, depending upon the number of times a day that load response is offered, as shown in Table 4.2.

Table 4.2 Minimum Income from Participation in Balancing Mechanism*.

Number of half-hours participation	Potential Income (€/customer/year)
1	8.0
2	15.7
3	23.1

* Assuming participants participate for the stated number of half-hours on a daily basis during the winter (i.e. 212 days 05 October to 04 May)

The values shown in Table 4.2 reflect the value of offering demand response into the balancing mechanism, and do not take account of the impact on the energy consumption of households. Here it is assumed that the energy use is avoided, and that no heat recovery takes place after a demand response event. In practice, however, it is likely that some heat recovery would be incurred, with a consequential impact on energy consumption. It has been estimated that the heat recovery could be as much as 50% to 75% of the avoided energy use[18].

However, it is important to note that the impact on overall energy consumption is a significant element of the business case. A ruling in 2009, by France's energy regulator, determined that Aggregators are required to compensate energy utilities for any loss of revenue due to any reduction in energy consumption. This ruling has a significant impact on the business case from the perspective of the Aggregator[19].

Using the imbalance prices provides an indication of the 'minimum' level of income that the householders could earn if they participated in the balancing mechanism on a daily basis during the heating season. In practice, it is more likely, that demand response would be offered during peak periods only, as an cheaper alternative to expensive peaking plant.

Therefore, taking the approach adopted in the previous case study, a comparison is made between the following two options:

- Option 1, the TSO purchases upward balancing from a new 1 MW peaking power plant, that is assumed to operate with a load factor of 5%; and
- Option 2, the equivalent amount of downward balancing is provided by 1MW of aggregated demand response.

[18] Estimation provided by Mines Paris.
[19] Article presented in French Business Magazine, Challenges, July 2009, "Les fournisseurs d'électricité trop représentés à la CRE ? ", available at http://www.challenges.fr/

Thus, as for the previous case study, the cost per unit of electricity from the peaking power plant would need to be €168/MWh for the generator to breakeven over 20 years, assuming a discount factor of 7.5%. (See Step 4, Aggregator Approach, Section 3).

As previously stated, uncertainty exists over the level of investment required for the control, monitoring and communication technology required to implement the demand response. Therefore, it is considered useful to consider a range of technology costs, as summarised in Table 4.3, which also shows the unit cost per MWh of demand response required by the Aggregator to breakeven over the same 20 years period, assuming a discount factor of 7.5%.

Table 4.3 Range of Control, Monitoring and Communications Technology Costs in French Case Study

	Scenario			
	(1)	(2)	(3)	(4)
Up-front (€/customer)	50	100	200	300
On-going (€/customer/year)	5	10	20	30
Unit cost to breakeven (€/MWh)	28	57	114	171

At the highest level of technology costs assumed here, i.e. €300/customer upfront and €30/customer/year ongoing, there is no benefit to the TSO of purchasing demand response rather than the output of peaking generation plant, with the unit price in both cases being €171/MWh. However, if technology costs were reduced, to say €200/customer upfront and €20/customer/year ongoing, the saving to the TSO would be €54/MWh, a saving of over 30%.

In this case, it is assumed that in return for participating in the demand response program, the consumer is provided with an in-home display that provides information on the electricity consumption in real time. The benefit to the consumer is then defined in terms of the potential energy cost savings that could be delivered as a result of the provision of improved information on electricity consumption. This is the approach that was adopted by an Aggregator in France that claims energy savings of 5% to 10%[20]. Thus, for an energy tariff of 0.11c€/kWh[21], the annual cost saving for an average consumer[22] would be around €50 to €100 per annum. It is also worth noting that the technical architecture components required to deliver the demand response will consume energy. If it is assumed that the power consumption is around 5 to 10W, the total energy consumption equates to around 44 to 88 kWh/year, equivalent to around €5 to €10 per annum.

A White Certificate Trading Scheme has been in place in France since 2006. Under the arrangements, Energy Suppliers were obliged to deliver 54TWh (cumulative) of total energy savings over the three years to 2009. Therefore, it is possible that the energy savings could be eligible to quality for White Certificates. This would require the Aggregator to provide evidence to demonstrate the level of savings that have been delivered. A number of approaches to this are possible, including a deemed savings approach, whereby the savings attributable to a certain measure are fixed ex-ante (i.e. in advance). This is the approach adopted in the UK's Carbon Emission Reduction Target (CERT) program, where, for example, real time displays are attributed with making 3.5% energy savings[23]. The acceptability of such an approach within the French scheme is, however, unknown.

[20] Voltalis, information available at http://www.nexity.fr/files/webform/Nexity%20Voltalis%20partnership.pdf
[21] Example tariff charged by EDF, available at http://www.edf-bleuciel.fr
[22] Based on an average consumption of around 9,000 kWh/year
[23] Carbon Emissions Reduction Target (CERT) 2008-2011 Supplier Guidance Amendments, Ofgem Consultation, Published 16 July 2009

The value of White Certificates depends upon prevailing market conditions, but an upper limit is given by the value of the penalty for non-compliance (2c€/kWh), the payment of which cancels the obligation[24]. Here, kWh refers to the discounted final energy savings over the lifetime of the project. Thus, using the discount rate of 4% (as prescribed within the White Certificate scheme), and a lifetime of 10years (as used in this case study analyses), the cumulated electricity savings for a typical household would be around 3,600 kWh (for a 5% energy saving) or 7,200 kWh (for a 10% energy saving). Thus, at 2c€/kWh the white certificates would be worth around €72 to €144 to each household. This is a relatively modest amount over the 10 year period. These figures relate to a business case extending over the lifetime of the technology. However, it is important to note that in practice, the maximum duration of the contract between the aggregator and the customer is currently fixed at three years.

Step 5 - Future Add-ins

There is no mechanism in place for demand side providers to offer frequency response, reserve or constraint management services to the TSO. As such, no future add-ins are considered here.

[24] Description of the French White Certificate Scheme, obtained from http://www.iea.org/work/2006/renewableheating/Session2/Paper_Description%20French%20Scheme_JURCZAC.pdf

5 Case Study 3: Energy efficient air-conditioning equipment, Greece

Step 1 - The Problem

Most of the Greek Islands in the Eastern Aegean sea do not form part of Greece's interconnected electricity system. The market is not liberalised in these islands. Therefore, electricity prices charged by PPC, the integrated monopoly Supplier and generator for the Islands, are regulated by the Regulatory Authority for Energy.

However, because electricity is generated by diesel generators, supplemented by a small amount of wind generation, the cost to PPC of generating the electricity is higher than the regulated tariff paid by consumers. As shown in the Table below, the regulated tariff represents 46 to 76% of the cost to PPC to supply that electricity.

Table 5.1 Cost to Supply and Regulated Tariff for LV Customers Selected Islands in the Eastern Aegean Sea[25]

Island	€/MWh	
	Cost of energy supply	Regulated tariff
Lesbos	224	113
Samos	195	117
Syros	254	117
Chios	151	116
Rhodes	239	119

Therefore, there is an incentive on PPC to identify options to reduce the amount of energy consumed on the islands, where the cost of implementing the savings is lower than the deficit in electricity revenues.

Step 2 - Target process

Energy consumption in Greece peaks during the summer, with air-conditioning loads of small consumers connected to the low voltage network accounting for the majority of electricity consumed, as indicated in Figure 5.1.

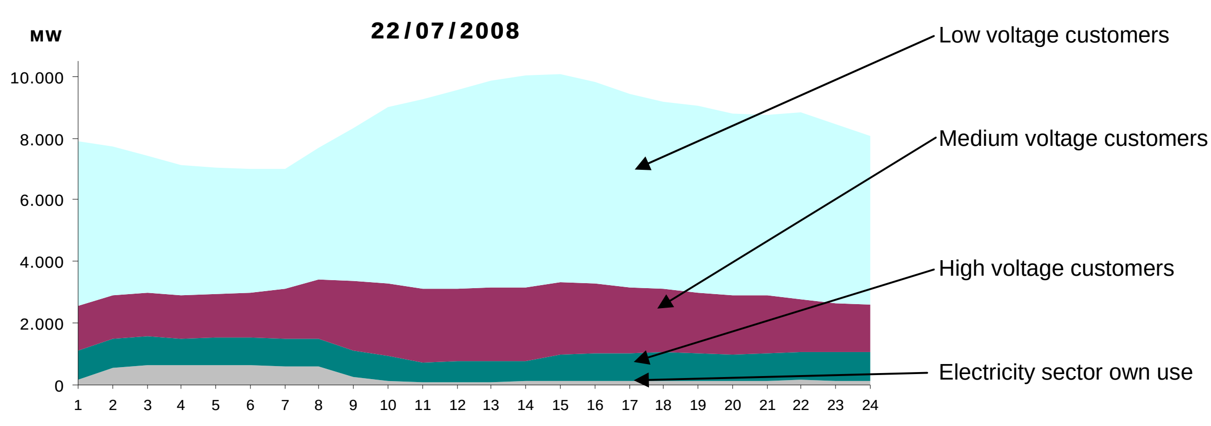

Figure 5.1 Energy consumption profile of Greek Consumers

25 Data for 2008 provided by PPC

Therefore, the replacement of existing, energy inefficient air-conditioning units with more efficient versions would significantly reduce electricity consumption during the peak periods. The incorporation of direct load control into the air-conditioning units would further enhance the peak load reduction.

Households in Greece typically have two split air to air systems each rated at approximately 9,000 BTU/h. Existing systems are typically D-class units consuming energy at a rate of around 0.9 kW and costing around €400. High efficiency units (A-class) units typically consume two-thirds of the energy of the D-class units (i.e. around 0.6 kW) but are double the cost (i.e. €800).

An example load profile of air-conditioning in Greece has been developed based on the following assumptions on the hours of operation:

Table 5.2 Assumed hours of operation of air-conditioning system

Season	No. days / season	Hours per day operation	Total hours
Winter	155	0	0
Spring	48	5	240
Summer	70	6	420
Peak Summer	44	7	308
Autumn	48	3	144
Total	**365**		**1,112**

Thus the annual energy consumption of an existing air-conditioning unit is assumed to be 1,012 kWh per year, compared to 660 kWh per year for a high efficiency unit. Hence the annual energy savings associated with the use of a high efficiency air-conditioning unit is assumed to be 352 kWh per year, equivalent to around €40 per year, assuming a regulated tariff of €113/MWh.

Step 3 - Control, Monitoring and Communications Technology

In this example, the focus is on the replacement of existing air-conditioning systems with a more efficient alternative. Therefore, there is no requirement for additional control, monitoring and communication technology.

Step 4 - Business Case

As indicated in Steps 1 and 2 the main focus of the problem is to reduce the amount of energy consumed on the islands, by encouraging consumers to replace existing air-conditioning units with an energy efficient alternative, thereby reducing the energy supply costs to PPC. The business case will therefore look to create a win/win situation for the householder and the Energy Supplier.

With an annual energy cost saving of around €40 per year, it would take 10 years for the consumers to recover the additional capital costs of €400 associated with the high efficiency units. Therefore, there is little incentive for householders to invest in energy efficient air-conditioning equipment. However, the provision of a subsidy to contribute towards the cost of energy efficient units could provide the incentive required to motivate households to replace their existing inefficient units, whilst also providing a return for PPC.

A discounted cash flow analysis shows that providing the householder with a €200 subsidy, results in a saving (i.e. a NPV) of around €84 over a 15 year period (assuming a 7.5% discount rate).

From the perspective of PPC, the energy cost saving is equivalent to almost €80 per unit replaced. Thus, again using a discounted cash flow analysis, the provision of a €200 subsidy yields an NPV of €350 per household over the 15 year period.

Step 5 - Future Add-ins

Due to its significant contribution to peak loads, it would seem reasonable to consider options for reducing energy consumption by air-conditioning during peak periods. One possible approach could be the application of Critical Peak Pricing (CPP). In this situation, there would be a need to introduce smart meters, estimated, in this case, to cost around €150 per meter. The business case also assumes the provision of a controller to automatically switch off the air-conditioning unit during critical peak pricing periods. Here, it is assumed that this is included within the cost of the energy efficient air-conditioning unit.

Thus, in this scenario, the Supplier would be the most likely to take on the role of the Aggregator. In this case, the benefit to the Supplier would be the avoided cost of peak power, whilst the benefit to the Customer would be the reduced energy costs associated with the new pricing structure.

Figure 5.2 below shows the impact of annual net benefit on the overall NPV from the perspective of the Supplier. This implies that, in this case, CPP would need to be able to deliver annual benefits to the Supplier of at least €22/customer/year to cover the up-front costs of the smart metering. However, it is important to note, as highlighted in Report 1, smart metering has the potential to deliver a range of benefits to the Supplier, such as improved customer service. It is not within the scope of this project to include a full analysis of such benefits, therefore, only the benefits attributable to CPP are considered here.

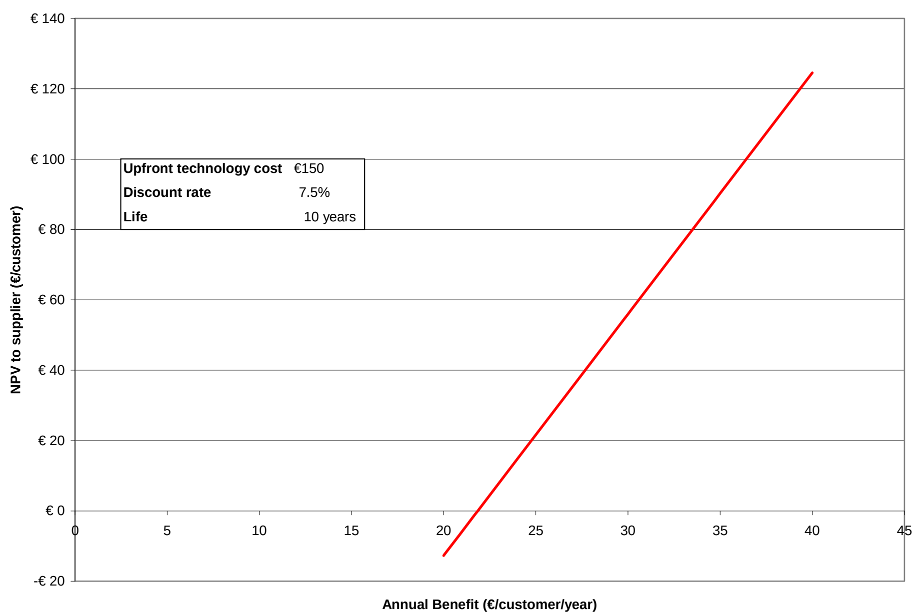

Figure 5.2 Potential NPV to Supplier of investment in smart metering to facilitate implementation of Critical Peak Pricing

CPP has been shown to deliver peak load reductions of 10% to 15% (or even greater in some cases)[26], provided that the price differential is sufficiently large. If the implementation of Critical Peak Pricing could deliver a peak load reduction of around 1kW over a two hour window, the maximum energy cost saving to the Supplier (based on a cost to supply of €224/MWh from Table 5.1) would be around €0.4/customer. Assuming 50 critical peak days per year, this equates to an annual benefit to the Supplier of around €22/year. It is important to note that this rather simplistic approach does not reflect how the cost of generation varies throughout the day. However, it does serve to provide a useful indication of the order of magnitude of the potential benefits that might be achieved. However, given that peak electricity prices can often be significantly higher than the average price, as described in Case Study 1, there is every likelihood that CPP could deliver sufficient benefits to justify the investment in new metering technology, particularly if other benefits, such as improved customer service, could be realised by the Aggregator.

[26] See Section 5, Requirements and Options for Effective Delivery, March 2010, Task XIX of the IEA DSM Programme

6 Case Study 4: Mass installation of energy efficient lighting, India

Step 1 - The Problem

India has a 12 to 13% shortage in power during peak hours, which typically occur between 17:00 hours and 23:00 hours. As a result of these shortages, black outs are commonplace. For the year 2009/2010, the Central Electricity Authority projected peak power shortages of 12.6 % or 14.98 GW. Further compounding the situation is the fact that total demand for electricity continues to rise.

There are plans in place to add 78.7 GW of power generation during the five year period ending March 2012, of which 15.1 GW has been commissioned (as of July 2010). However, it is predicted that the 78.7 GW target will not be achieved, mainly due to a shortage of equipment.

Therefore, demand side solutions are considered to be an essential component of a package of measures to deliver India's energy requirements during peak periods.

Step 2 - Target process

Domestic appliances and lighting accounts for almost 22% of the total electricity demand in India, and the end-uses are the are the principal contributors to the peak load.

It is estimated that there are over 400 million lighting points in India that use Incandescent Lamps (ICLs). ICLs are extremely energy in-efficient, with just 5% of the electricity input converted to light., with the remaining energy lost as heat. In recent years the Compact Fluorescent Lamp (CFL) has emerged as an energy efficient alternative - CFLs use around one-fifth as much electricity as an ICL to provide the same amount of illumination.

It has been estimated that the replacement of ICLs with CFLs would lead to a potential reduction of over 6,000 MW in electricity demand. The replacement potential of ICLs with CFLs is also borne out of the fact that in the year 2008, ICL sales in India were 734 million compared to sales of just 199 million for CFLs[27] The penetration of incandescent lamps for lighting in the commercial and residential sectors combined is thus nearly 80% in India.

Hence, it is not surprising to note that CFL sales have grown from 35 million in 2003 to more than 199 million in 2008. However the majority of the CFL sales take place in the commercial sector and not the residential sector. The reasons for this are:

- the domestic electricity tariff is very low (INR 1.2 to 5.6) as compared to a much higher commercial sector tariff (INR 4 to 11);
- the average hours of use in the commercial sector of CFLs is much more (> 5 hours/day) than the domestic sector (~ 3-4 hours/day), leading to a faster return on investment; and
- the CFL first cost is a barrier for the domestic household sector. In the year 2009 a CFL would cost around INR 80-130. On the other hand, an ICL costs just INR 10-15.

[27] Information provided by Bureau of Energy Eifficiency

For the purposes of this analysis, it is assumed that four incandescent lamps (2 x 60W lamps and 2 x 100W lamps) are replaced with four CFLs (2 x 14W lamps and 2 x 23W lamps respectively).

The following table therefore summarises the annual energy consumption of the incandescent lamps and the CFLs, based on 3.5 hours operation per day.

Table 6.1 Annual Energy Consumption Assumptions

	Number / Rating of lamps	**Annual Consumption (kWh / year)**
Incandescent	2 x 60W 2 x 100W	408
CFLs	2 x 14W 2 x 23W	94
Saving		**314**

Step 3 - Control, Monitoring and Communications Technology

As in the previous example, the focus is on the replacement of an existing end use technology with a more efficient alterative. Therefore, there is no requirement for additional control, monitoring and communication technology.

Step 4 - Business Case

As stated at Step 1, the problem to be addressed is the predicted peak power shortages faced by the Distribution Companies that supply electricity to end-users. The Business case will therefore look to create a win/win/win situation for:

- The Distribution Companies (Discoms)
- The householders
- An Aggregator or Energy Saving Service Provider

There are a number of approaches that could be adopted to achieve this. These might include:

- a predominantly Customer focussed approach;
- an approach that leans heavily on the Clean Development Mechanism (CDM); and
- an approach based on the “Supplier” model – in this case led by the Discoms themselves.

The Indian Energy Conservation Act, 2001 under section 13 provides the Bureau of Energy Efficiency (BEE) the powers to:

- formulate and facilitate demonstration projects for promotion of efficient use of energy and
- promote innovative financing of energy efficiency projects

Further, the National Mission for Enhanced Efficiency under the National Action Plan for Climate Change also prompts the BEE to accelerate the shift towards energy efficient appliances. The Bachat Lamp Yojana (BLY) scheme is an indirect outcome of the above policy scenario. Hence, the objective of BLY is to replace ICLs with quality long-life CFLs amongst residential users in India. The CFLs distributed under the scheme would follow the Bureau of Indian Standards (BIS) mandated technical specifications for self-ballasted CFLs[28].

The Bureau of Energy Efficiency has developed and registered a CDM programme of activity "Bachat Lamp Yojana "with the UNFCCC[29]. The BLY is a scheme developed by the Bureau of Energy Efficiency (BEE) to promote energy efficient lighting for households in India. The BEE is acting as the coordinating and managing entity for the Programme of Activities (PoA) 'Bachat Lamp Yojana'. The CPA implementer(s) develop and implement the CDM Programme Activities (CPAs) through collaboration with Electricity Distribution Companies (SEB /Discoms). Whilst it is the CDM approach that has been adopted in India, the other approaches are, potentially, equally as valid. Thus, each of the three potential options listed above are considered in the following Sections.

Customer Focussed Approach

The cost of CFL lamps is considerably higher than the equivalent cost of an incandescent lamp. Typical costs are 80 to 130 Indian Rupees (INR) for CFLs compared to 10 to 15 INR for incandescent lamps.

However, the expected lifetimes of CFLs are longer, typically 10,000 hours (compared to 750 for incandescent) and energy use is lower (as noted above under **Target Process**)

- The energy consumption of 2 x 60 W and 2 x 100W incandescent lamps operating 3.5 hours per day is 408 kWh / year
- The energy consumption of 2 x 14W and 2 x 23 W CFLs operating 3.5 hours per day is 94 kWh / year
- Over a 10 year period it would be expected that the householder would need to purchase two sets CFLs at a cost of 420 INR per set of four.
- If incandescent lamps were used, then, over the same 10 year period, 18 sets of lamps, at a cost of 50 INR per set of four, would be required

Assuming an electricity cost of 3.4 INR/kWh, a discounted cash flow analysis over the 10 year period (taking account of both capital and running costs) shows that the customer (householder) would expect to save some 5,400 INR (assuming a 15% discount rate). Thus, the well the informed customer might be expected to make this purchase anyway.

However, the problem is the high up-front capital cost and in most cases, (particularly in low income households) the customer will not buy the more expensive CFL. A potential solution could therefore involve an Aggregator funding the purchase of the CFLs and then sharing the cost energy savings with the householders. In this case, energy savings would need to be agreed between the Aggregator and the householder. Options for determining the energy savings include:

a) using deemed savings (thus the agreement becomes effectively a rental or surcharge), or
b) using actual monitored savings (e.g. using a micro-chip in each light to record actual lamp run-hours)

Thus, a summary of the stakeholder benefits for the customer focussed scenario is provided in Table 6.2 below.

[28] IS 15111:2002
[29] Ref. No. 3223

Table 6.2 Summary of stakeholder benefits: Customer Focussed Scenario

Stakeholder	Benefit
Customer	Reduced energy bills
Discom	Reduced peak energy use
Aggregator	New business supplying CFLs

Clean Development Mechanism

The CDM forms part of the Kyoto Protocol on greenhouse gas reductions. It allows industrialised countries with a greenhouse gas reduction commitment to invest in ventures that reduce emissions in developing countries, as an alternative to more expensive emission reductions in their own countries.

Once a CDM project is approved and implemented, the applicant (the industrialised country) receives Certified Emission Reductions (CERs), which are commonly known as Carbon Credits. CERs for CDM projects currently trade at around € 10 to €12 per tonne CO_2 equivalent[30].

In the Bachat Lamp Yojana, the lamp manufacturers provide CFLs to households at the same cost as incandescent lamps, and the cost difference of CFLs and incandescent lamps is recovered through the CDM.

- The cost difference is say 370 INR (for four CFLs, the maximum permitted per household under the scheme)
- The total annual energy saved is 314 kWh per household (2,460kWh over the lifetime of the CFLs.)
- Carbon saved is 167 kg CO_2 per household per year (1.3 tonnes of CO_2 per household over the lifetime of the CFLs)

Cost per tonne CO_2 is therefore 2.2 INR/kg CO_2 or €37 per tonne CO_2 saved[31]. Although this is higher than the traded CER cost noted above, it is likely to still be competitive with alterative carbon abatement measures within the applicant industrial country.

Thus, a summary of the stakeholder benefits is provided in Table 6.3 below.

Table 6.3 Summary of stakeholder benefits: Clean Development Mechanism

Stakeholder	Benefit
Customer	Reduced energy bills, with no additional cost for lamp purchase
Discom	Reduced peak energy use
Energy Service Provider*	Low cost CERs

* the applicant, industrialised, country

30 Futures prices for CER trades on the European Climate Change during March 2010.
31 Based on an exchange rate of 1 INR = €0.0166

The Supplier Model

In most Liberalised Electricity Markets, the obligation to meet electricity demand falls on the Electricity Supply Company (the Supplier). The Supplier must buy sufficient energy to meet demand in each trading period. Thus, in a situation where there is a shortage of generation available to meet demand, the Supplier will expect to pay a premium price for that energy.

One method of determining the peak price per kWh, in a situation where there is a shortage of capacity, is to look at the costs associated with investing in new peaking power plant. Typical costs are[32]:

- Capital cost of peaking power plant - $634/kW (28,530 INR/kW[33])
- Staff / maintenance costs - $10.53/kW (474 INR/kW)
- Fuel costs - $3.17/kWh (143 INR/kW)

Assuming:

- a lifetime of 30 years, and
- a load factor of 15% (i.e. operation of 1,314 hours per year)

Then, the cost per unit of electricity to breakeven would need to be 3,457 INR/MWh

The cost of supplying four CFLs at the same purchase price as the four equivalent incandescent lamps is 370 INR per household, (as noted above) which is equivalent to providing electricity at 249 INR/MWh.

Hence there is a clear advantage to using the CFLs.

The Aggregator, or Energy Service Provider can then make a business case based on selling the reduced peak consumption to the Supplier (in this case there is a clear advantage to the Supply company and the Aggregator being one and the same, since it reduces, or even eliminates, the need to monitor savings).

Thus, a summary of the stakeholder benefits is provided in Table 6.4 below.

Table 6.4 Summary of stakeholder benefits: Supplier Model

Stakeholder	Benefit
Customer	Reduced energy bills, with no additional cost for lamp purchase
Discom	Reduced peak energy use Lower cost of meeting peak demand
Energy Service Provider	Income stream from selling energy savings to the Supplier

32 Costs are for an advanced combustion turbine, US Energy Information Administration, see Appendix 2 for further details

33 Based on an exchange rate of 1US$ = 45 INR

Step 5 – Future Add-ins

In this case, a potential future add-in could be the provision of end-use monitoring and feedback to encourage households to minimise energy wastage. Potential approaches include:

- Direct feedback – such as real time displays
- Indirect feedback – such as frequent / informative billing
- Other approaches – such as energy advice via community based programmes or face to face audits

In this particular example, it is believed that a number of the CFLs were fitted with a microprocessor to enable the run hours of the energy efficient lamps to be monitored as part of the verification process under the CDM. This information could be used by the CEA to evaluate the operation of light bulbs in typical homes, and used to provide information to households on the energy cost implications of leaving lights on unnecessarily. Informative billing could also show how consumption has changed relative to the same period in a previous year. This could be a particularly useful mechanism to demonstrate to the householder the benefit of CFLs, with the potential of encouraging householders to actively consider their purchase. Bills could also provide a comparison of a household's consumption relative to other similar households. Such information has been demonstrated to deliver energy savings ranging from 0 to 12%[34].

[34] The effectiveness of feedback on energy consumption, A review for DEFRA of the literature on metering, billing and direct displays, Sarah Darby, April 2006

7 Case Study 5: Direct load control of commercial air-conditioning, UK[35]

Step 1 - The Problem

At certain times of the day National Grid, the GB Transmission System Operator, secures services, either output from generators or reduction in demand, in order to deal with failures of generation plant or unexpected fluctuations in demand. These services comprise both synchronised and non-synchronised resources. The non-synchronised requirement is primarily secured through contracts for Short Term Operating Reserve (STOR), which is provided by a range of service providers by means of standby generation and/or demand reduction.

A typical demand side provider of STOR would, upon receipt of an electronic instruction from National Grid, be able to start back up generation and/or reduce electricity demand within timescales of up to four hours, and be able to run for a couple of hours.

National Grid, has identified an increasing need for Balancing Services[36], particularly the provision of Reserve Services, which is unlikely to be met by existing providers of Balancing Services. As indicated in Table 7.1, the annual requirements for STOR is forecast to increase from just over 3 TWh per annum for 2010/11 to over 8 TWh per annum by 2025/26. The cost of meeting these requirements is expected to increase from £311m to £690m per annum over the 15 years.

Table 7.1 Forecast Requirements and Costs for STOR, GB[i]

	Year			
	2010/11	**2016.17**	**2020/21**	**2025/26**
Reserve (TWh)	3.13	4.57	7.37	8.37
Cost (£million)	200.6	256.5	410.9	519.3
Total Cost[ii] (£million)	311.4	376.8	566.1	690.3

i) Table 5, Operating the Electricity Transmission Networks in 2020, National Grid, June 2009
ii) Includes contracted service cost and utilisation costs

In addition, an increasing requirement for frequency response has been identified under a review of *planning standards for investment* and *standards for planning and operating the system in real time*. The Review[37] identified that a further £105 million per year will be required for additional frequency response to accommodate larger 1320MW nuclear generation plant, the development of which are considered a key element of meeting UK greenhouse gas emission targets.

35 This Case Study relates specifically to Great Britain, i.e. England, Wales and Scotland only, rather to the United Kingdom as a whole, which also includes Northern Ireland.
36 National Grid 'Initial Consultation: Operating the Electricity Transmission Networks in 2020', available at http://www.nationalgrid.com/uk/Electricity/Operating+in+2020/
37 SQSS Fundamental Review GSR007, http://www.nationalgrid.com/uk/Electricity/Codes/gbsqsscode/reviews/index.htm

Step 2 - Target process

As highlighted in Report 1[38], cooling and ventilation accounts for almost 10% of the electricity consumed by the Service Sector in GB. Cooling and ventilation electricity consumption is greatest in the commercial office sector, where it accounts for around a fifth of total electricity consumed. Whilst most of this is likely to relate to large commercial buildings, including data centres, with high IT requirements largely responsible for driving the need for cooling and ventilation, some will also relate to smaller buildings. This is evidenced, to some extent, by the significant volume of packaged air-conditioning units that are sold in the UK. Packaged air-conditioning units are more suited to the SME sector (i.e. for small buildings), and as Table 7.2 shows, the market for such units is not insignificant[39], despite the UK's temperate climate.

Table 7.2 Sales of Packaged Air-Conditioners in the UK in 2007

Type of packaged unit	Number of units
Portable	87,600
Window / through wall	2,100
Split	221,284
Roof top units	2,200
Close control	8,190

There is also growing evidence of increased loading of existing distribution substations in urban areas, driven by a significant increase in air-conditioning load[40].

Air-conditioning, is an ideal application for demand response, as it can be interrupted at little or no notice, and provided the interruption is not sustained for too long, causes minimal disruption to users.

The energy consumption profile associated with air-conditioning of a particular building will be a function of a number of factors. These include both external conditions (such as external temperature and solar irradiance), as well as user related factors such as occupancy pattern and building usage. As such it is difficult to determine an energy consumption profile for a '*typical*' building. Therefore, the analysis here considers three example air-conditioning profiles to examine the extent to which the air-conditioning energy consumption profile impacts on the business case. In each scenario, the power consumption of the unit is assumed to be 2kW, broadly equivalent to that of a single split air-conditioning unit capable of delivering around 6kW of cooling.

In Scenario 1, air-conditioning operates only during summer weekdays. Under Scenario 2, air-conditioning is required during day-time hours on an annual basis, and for Scenario 3, the air-conditioning is assumed to operate 24 hours per day 365 days per year. As indicated in Table 7.3, the consumption varies from 1,884 kWh / year when cooling is required on summer weekdays only, up to 17,520kWh / year when cooling is required 24 hours per day throughout the year.

38 See Appendix 3: - Requirements and Options for Effective Delivery, March 2010, Task XIX of the IEA DSM Programme

39 http://www.bsria.co.uk/news/ac-market/

40 Demand side management:Benefits and Challenges, GoranStrbac, Energy Policy 36 (2008) 4419–4426

Table 7.3 Air Conditioning Load Energy Profile Characteristics

Scenario	Seasons	Days per week	Operation	Annual Consumption (kWh/year)
A	Summer only	Weekdays	Day-time*	1,884
B	All year round	Weekdays	Day-time*	5,690
C	All year round	Weekdays & Weekends	All Day	17,520

* Day-time operation is between 07:30 to 18:30

Step 3 - Control, Monitoring and Communications Technology

Whereas the operation for large central cooling plant will normally be controlled by the building's energy management system, the same is not necessarily true for packaged units. These are typically controlled via a local thermostat, with manual on/off control. The following sections, therefore consider the technical architecture components that might be required to facilitate direct control of such packaged air-conditioning systems.

Controller

There are a number of options for controlling packaged air-conditioning units, ranging from simple manual control to direct load control by the Aggregator. It is unlikely that manual control could be relied upon to deliver a guaranteed level of response, therefore direct load control is considered the only viable option.

Direct load control could be implemented using a number of approaches including:

- Increasing the set point of the thermostat, to reduce the amount of cooling provided;
- Turning of the entire air-conditioning unit; and
- Turning off the compressor, whilst allowing the fan to operate.

The latter two options, i.e. turning off either the entire air-conditioning unit or just the compressor, are considered to be the only viable approaches for delivering reserve services to the TSO. In particular, the response will be delivered 'as instructed', rather than as determined by the thermostat setting and the internal conditions. As such, this is the option considered here. However, evidence from field trials of controlling air-conditioning units suggests that turning off the compressor is more acceptable to end-users than turning off the entire air-conditioning unit. This can be achieved by fitting a thermistor in the return air stream to turn the compressor off by fooling the unit into thinking the desired temperature has been achieved. This approach was employed in a 2,000 customer trial in Australia, managed by ETSA[41]. Therefore, the latter approach is assumed to be adopted here.

Response Monitor

Currently, demand side providers of short term operating reserve are required, as a minimum, to have half-hourly metering. However, SME customers with a maximum demand of <100kWh generally have non-half-hourly metering, whereby their consumption is settled according to a deemed consumption profile. Under the plans for the roll out of smart meters in the UK, larger non-domestic customers will be required to have advanced meters by 2014, with smaller non-domestic customers required to have smart meters by 2020. The following diagram provides a high level overview of the functionality of advanced and smart meters.

[41] http://www.arema.com.au/demand_man_ctee.htm

Data collector

Smart metering	Key Features	Advanced metering
?	Half-hourly data	✓
✓	Multiple TOU billing registers	×
✓	Remote disconnect	×
✓	Remote configuration (for credit or prepay)	×
✓	Two-way communications	×

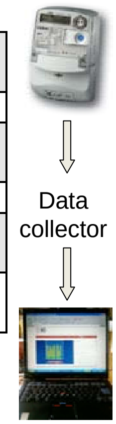

Figure 7.1 Advanced and smart metering functionality – high level overview

Advanced meters will provide half-hourly metering and meter reading capability, but no facility for two way communications. As such, the business case assumes that suitable half-hourly metering (either advanced or smart metering) will be in place, but that a dedicated communication gateway will be required.

Communications Gateway

As discussed above, it is assumed that a dedicated communications gateway will be required to receive the incoming instructions from the Aggregator and transmit these to individual air-conditioning units.

Internal Communication

As discussed in Report 1[42] the option exists for either one-way or two-way communication, which can either be ‘wired’ or ‘wireless’. In this case, it is assumed that one-way communication will be sufficient. The choice of wired or wireless communication has little effect on the effectiveness of service delivery, although ‘wired’ solutions may be unnecessarily intrusive and expensive. As such, it assumed that a one-way, wireless communication system, using one of the many proprietary platforms, such as Zigbee, Zwave and WiFi, would be suitable in this situation.

External Communication

The relatively long notice period associated with STOR (up to four hours), allows for greater flexibility over the communication approach that could be utilised compared to the situation where instantaneous response is required. As such, the option exists for simple one-way communication from the Aggregator to the end-user using PSTN, GSM or internet.

Step 4 - Business Case

As stated at Step 1, the problem to be addressed is the predicted increased requirement for short term operating reserve by the TSO. Thus, in coming years, the TSO has the option of either purchasing reserve services from ‘existing’ providers (i.e. generators) or alternatively, purchasing demand response services from an Aggregator. The Business case therefore looks to create a win/win/win situation for:

[42] See Section 8, - Requirements and Options for Effective Delivery, March 2010, Task XIX of the IEA DSM Programme

- The GB TSO (National Grid)
- The Consumer (Commercial Buildings)
- An Aggregator

In this analysis, it is assumed that all the income from the provision of reserve services is retained by the Aggregator. In return for participating, the SME is rewarded through the provision of energy saving advice by the Aggregator. This is the approach adopted by Aggregators that are targeting large commercial buildings[43].

Under the existing arrangements, there are two forms of payment for providers of short term operating reserve, an availability payment and an utilisation payment. The availability payments are made to providers to ensure that their units are made available within specified availability windows. Utilisation payments, however, are only paid for energy delivered upon specific instruction from the TSO.

Table 7.4 shows the average accepted availability and utilisation prices for contracts covering the period April 2009 to March 2010. As shown, the availability price ranges between £7.34/MW/h and £8.81/MW/h with the utilisation prices in the region of around £280/MWh.

Table 7.4 Overall Average Availability and Utilisation Prices STOR, 2009/10[44]

Dates	**1 April 2009 to 31st March 2010**					
Season	**3-1**	**3-2**	**3-3**	**3-4**	**3-5**	**3-6**
Total MW Accepted	2,597	2,712	2,343	2,585	2,751	2,745
Availability (£/MW/h)	£7.34	£7.42	£8.27	£8.43	£8.26	£8.27
Utilisation (£/MWh)	£288.07	£290.62	£276.89	£290.17	£290.23	£282.98

* Overall average prices for accepted bids

For the purposes of this analysis, it is assumed that the availability price is £7.00/MW/h and the utilisation price is £280/MWh.

There are two forms of the STOR service:
- **Committed Service:** where a service provider is required to make the service available for all Availability Windows within the contracted term; and
- **Flexible Service:** where the service provider has more flexibility over when the service is available.

For the Committed Service, the Availability Windows vary by season and by day type (i.e. weekdays, weekends and bank holidays), as shown in Table 7.5, which shows the availability windows for the 2009/2010 season.

43 For example, Schneider Electric
44 STOR Market Information Report: TR 09, National Grid

Table 7.5 Availability Windows for STOR - Committed Service[44]

		Half-hour			
		Weekdays		Weekends	
Season (*)		**From**	**To**	**From**	**To**
1 April 2009 to 27 April 2009	i	07:00	13:30	10:00	14:00
	ii	19:00	22:00	19:30	22:00
	iii				
27 April 2009– 17 August 2009	i	07:30	14:00	09:30	13:30
	ii	16:00	18:00	09:30	13:30
	iii	19:30	22:30		
17 August 2009– 21 September 2009	i	07:30	14:00	10:30	13:30
	ii	16:00	21:30	19:00	22:00
	iii				
21 September 2009– 26 October 2009	i	07:00	13:30	10:30	13:30
	ii	16:30	21:00	17:30	21:00
	iii				
26 October 2009 – 1 February 2010	i	07:00	13:30	10:30	13:30
	ii	16:00	21:00	16:00	20:30
	iii				
1 February 2010– 1 April 2010	i	07:00	13:30	10:30	13:30
	ii	16:30	21:00	16:30	21:00
	iii				

* from/to 05:00 hours on dates specified

For the purposes of this analysis, it is assumed that the service provider actively participates during the morning period only, with an assumed availability window of 07:30 to 13:30 throughout the season.

The income from the provision of STOR will depend upon the number of occasions that the service provider is requested to deliver reserve services by the TSO. Therefore, Table 7.6 shows how the potential income varies according to the number of occasions that the service is called.

Table 7.6 Potential Income from provision of short term operating reserve 1 x 2kW air-conditioning unit

	Frequency of service provision					
	10% of days (36 times per year)			20% of days (72 times per year)		
Cooling scenario	**A**	**B**	**C**	**A**	**B**	**C**
Potential Income (£/year/1,000 customers)						
1 x 2kW unit	12.5	43.3	65.1	22.8	71.0	103.2

Where: A = Summer cooling, daytime weekdays only
B = All year round cooling, daytime weekdays only
C = All year round cooling, 24 hours / day

As would be expected, the potential income is greatest under scenario 3 which has the potential to generate a revenue on a year round basis. In this case, the total annual income is £65 per customer if the service is called 36 times a year, increasing to £103 per customer if the service is called 72 times per year. Where cooling is utilised during weekdays only, albeit on a year round basis, the potential income ranges between £43/customer and £71/customer depending upon how often the service is called. When cooling is required only during the summer months, the income reduces to £12.5 per customer when the service is utilised 36 times a year, or £23 per customer when the service is used 72 times a year.

Figure 7.2 therefore shows the net benefit (or disbenefit) to the Aggregator for the following range of technology costs, as shown in Table 7.7.

Table 7.7 Technology costs for Direct Control of Air-Conditioning Case Study

	(1)	(2)	(3)	(4)
Up-front (€)	50	100	200	300
On-going (€/year)	5	10	20	30

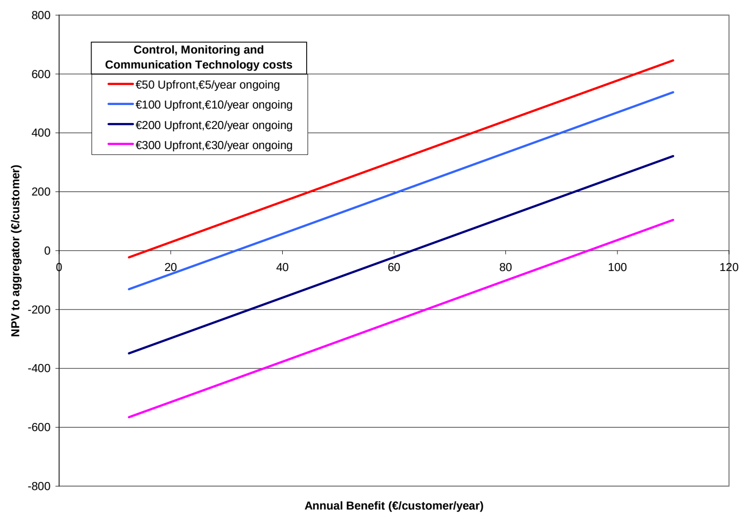

Figure 7.2 Potential NPV to Aggregator of Investment in New Technology to Enable Direct Control of Commercial Air-Conditioning

Thus, for upfront technology costs of £200 and ongoing costs of £20/year on a per customer basis, the annual benefit needs to be greater than £65/customer for the Aggregator to see a benefit over a 10 year period, assuming a discount rate of 7.5%. This implies, that if reserve is only called on 10% of days (i.e. 36 times year), an Aggregator would only be able to benefit (i.e. have a positive NPV) if the SMEs operate their air-conditioning 24 hours per day, 365 days per year. If, however, the Aggregator could rely on the service being called 72 times a year (i.e. on 20% of days), then the Aggregator would yield a positive NPV if the air-conditioning is operated during weekdays only, on a year round basis.

At technology costs of £100/customer upfront and £10/customer/year on-going, the Aggregator would see a positive NPV provided the annual benefit was at least £35/customer/year. Thus, indicating a potential business opportunity provided the air-conditioning was not limited to summer operation only. (See Table 7.6 for details of annual benefit for different cooling load profiles and reserve utilisation).

However, it is important to note that these results are based on a singe air-conditioning unit with a power rating of 2kW. It is possible that SMEs may have multiple units, either as multi-split systems or a number of individual units. Therefore, for example, a single SME, with four 2kW units available for participation in short term operating reserve, would provide an aggregator with a potential income ranging from £50/customer to £413/customer, as indicated in Table 7.8, depending upon the cooling profile and the number of times the service is utilised.

Table 7.8 Potential Income from provision of short term operating reserve 4 x 2kW air-conditioning units

	Frequency of service provision					
	10% of days (36 times per year)			20% of days (72 times per year)		
Cooling scenario	**A**	**B**	**C**	**A**	**B**	**C**
Potential Income (£/year/1,000 customers)						
4 x 2kW units	50.0	173.2	260.5	91.2	284.3	412.7

Where: A = Summer cooling, daytime weekdays only
B = All year round cooling, daytime weekdays only
C = All year round cooling, 24 hours / day

This would imply, that the Aggregator would make a positive net benefit under most of the circumstances considered here. The only exception being that the Aggregator would have a negative NPV for technology costs of £200 upfront and £20 per year ongoing (on a per customer basis) if the air-conditioning is used only during the summer and if the service is called only 36 times per year.

Step 5 - Future Add-ins

In this case, a potential future add-in could be the provision of Commercial Frequency Response services to the TSO. Commercial Frequency Response is a collection of services that can be provided by demand side participants and generation plant. The technical characteristics of these services are different to those required under mandatory service arrangements, and range from enhanced mandatory dynamic services through to non-dynamic services effected via low frequency relays. Under the current arrangements, providers of frequency response must be available 24 hours per day, 365 days per year and be able to provide the service for a minimum of 30 minutes.

Figure 7.3 shows the monthly volumes of commercial frequency response provided to National Grid together with the cost of securing these services[45] between April 2009 and November 2009.

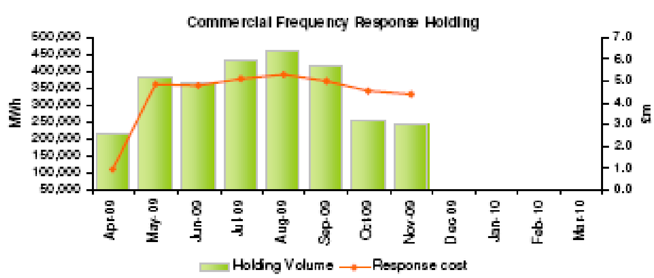

Figure 7.3 Commercial Frequency Response Volume and Cost

It is believed that demand side providers generally receive an availability payment per MW of available response per hour of availability, with no payment for utilisation. Thus, based on an average monthly cost of around £4.5m and an average volume of 350,000 MWh, as indicated in Figure 7.3, the average amount paid by National Grid for frequency response is around £13/MW/h.

45 Monthly Balancing Services Summary 2008/2009 October 2008, National Grid

The data shown in Figure 7.3 summates all the different providers of commercial frequency response which, with the exception of Fast Frequency Response, are negotiated bilaterally. Therefore, caution needs to be exercised in interpreting the information provided in Figure 7.3 to obtain indicative values for a specific service. In particular, dynamic frequency response services, such as Fast Frequency Response, is valued much higher than static response services provided by the demand side. Therefore, it is likely that the value of frequency response provided by the demand side will be considerably lower than £13/MW/h, which represents the average across all frequency response services.

Therefore, for the purposes of this analysis it is assumed that demand side providers can obtain a price of £6.50/MW/h. Thus, 2kW of load available 24 hours per day, 365 days per year would be able to earn £114 per annum. In this case, however, the technology costs would need to incorporate a low frequency relay capable of delivering the demand response within the near instantaneous timescales required by the TSO.

If it were possible to provide frequency response services on a limited basis, for example outside the reserve availability windows, then it would be possible for the Aggregator to earn income from the provision of both reserve and frequency response. However, this application would be best suited to sites where air-conditioning is used 24 hours per day. In terms of the SME sector, further research would be required to identify the extent to which such a market exists.

8 Discussion

The case studies presented in Sections 3 to 7 investigate whether a business case exists for delivering demand response and energy savings in five specific situations. A summary of the results from the five case studies is given in Table 8.1 below, each of which explores whether demand response and/or energy savings have the potential to provide a commercially viable solution to a specific issue (‘*the problem*’).

Table 8.1 Summary of Case Studies - Benefits

	Case Study	Approach	Benefits
1	Dynamic control of electric heater loads, Finland Residential	Supplier led:	**Total benefits:** €40 to €100/customer/year avoided peak spot prices – shared between customer and Supplier
		Aggregator led:	**Supplier benefits:** €84/MWh avoided peak power purchase **Aggregator benefits:** Business selling demand response at €84/MWh to Suppliers **Customer benefits:** Energy savings advice from Aggregator
2	Dynamic response of residential heating loads, France Residential	Aggregator led:	**To TSO:** Up to €143/MWh avoided peak power purchase **To Aggregator:** Business selling demand response to TSO at €28/MWh to €171/MWh **To customer:** €50 to €100/year energy savings
3	Energy efficient air-conditioning equipment, Greece Residential / SME	Supplier led:	**To Energy Supplier:** €80/customer/year energy savings / NPV of €350 **To customer:** €40/customer/year energy savings / NPV of €84
4	Mass installation of energy efficient lighting, India Residential	Customer led:	**To customer:** 1,070 INR/year (~€18/year) energy savings NPV of 5,400 INR (~€93)
		Clean Development Mechanism:	**Sponsoring country:** 167kg CO_2 savings/household at 2.2 INR/kg CO_2 (€37 per tonne of CO_2) **To customer:** 1,070 INR/year (~€18/year) energy savings
		Supplier led:	**To Energy Supplier:** 3,208 INR/MWh (~€55/MWh) avoided peak power purchase **To customer:** 1,070 INR/year (~€18/year) energy savings
5	Direct load control of commercial air-conditioning, UK SME	Aggregator led:	**To TSO:** Avoided shortfall of reserve services through availability of demand resource at equivalent price to conventional generation sources. **To Aggregator:** Business selling demand response to TSO, earning £13 to £206/customer/year (~€15 to ~€240 /customer /year) **To Customer:** Energy savings advice from Aggregator

As highlighted in Table 8.1, the benefits associated with demand response and energy savings vary between the case studies. From the perspective of the buyer (i.e. the organisation with a specific problem to be solved), the benefits include avoided peak power purchases worth up to €143/MWh (Case Studies 1, 2, and 4), avoided losses on the sale of electricity at prices lower than the cost to supply (Case Study 3), and the avoided shortfall of reserve services (Case Study 5).

From the perspective of the consumer, the benefits include potential energy savings that could be realised if the consumer acts upon energy efficiency advice or responds to information provided via EUMF (Case Studies 2 and 5). Energy cost savings were specifically identified in two of the Case Studies (3 and 4), where the savings ranged from between €40/year and ~ €18/year, respectively. Whether such savings are sufficient to motivate consumers to participate is not explored within the scope of the project. However, the amount of money involved is considered to be relatively low, and therefore unlikely to provide a huge incentive to encourage customers to participate. Research undertaken by the Consumer First Panel suggests that savings of around £10/month (~€11/month) would be required by consumers in order to drive changes in their behaviour[46].

In a number of the case studies, the Aggregator is assumed to retain the income from the sale of demand response. In return, the consumer is rewarded via the provision of energy savings advice provided by the Aggregator. No attempt has been made to quantify the level of such savings, or more importantly, whether the 'promise' of such energy savings is sufficient to motivate consumers to participate. However, if the Aggregator is able to verify the level of energy savings that can be delivered, the possibility exists for the energy savings to earn White Certificates, which, when traded, could be used to provide additional incentives to the consumers. This has been explored briefly in Section 4.

From the perspective of the Aggregator, the case studies demonstrate that whilst the development of demand response and energy saving products do offer the potential for a commercially viable business, this is very much predicated on the cost of the communication, monitoring and control technology. Therefore, Table 8.2 shows, where applicable, the technology costs required to deliver a project with a zero NPV at the lowest and highest level of benefits, i.e. the breakeven technology costs.

[46] Raised during Ofgem Stakeholder Roundtable, 14 September 2009

Table 8.2 Summary of Case Studies – Break Even Technology Costs*

	Case Study	Consumer Segment	Lowest Annual Benefits	Highest Annual Benefits
1	Dynamic control of electric heater loads, Finland	Residential	Customer led: ~€160 Supplier led: ~€140	Customer led: ~€400 Supplier led: ~€350
2	Dynamic response of residential heating loads, France	Residential	€50	€300
3	Energy efficient air-conditioning equipment, Greece	Residential / SME	n/a	n/a
4	Mass installation of energy efficient lighting, India	Residential	n/a	n/a
5	Direct load control of commercial air-conditioning, UK	SME	£40 (~€45)	£650 (~€750)

(*) Technology costs required to deliver a project with a zero NPV.

Thus, for Case Study 1, with annual benefits of €40/customer/year, the up-front technology costs need to be no more than €160/customer for the project to breakeven for a customer led approach. For a Supplier led approach, where the benefits are shared between two parties, the technologies costs need to be €140/customer, as the Supplier now retains only 90% of the overall benefits. In Case Studies 2 and 5, however, the technology costs can be significantly lower, at around €50/customer if annual benefits are at the low estimate.

If however the benefits are at the upper range of those estimated, the technology costs required to breakeven range between €300 and £650 (~€750), as shown in Table 8.2. Given the typical costs of similar control, monitoring and communication technologies (see Appendix 1), this would suggest that the viability of the business case requires that the higher level of benefits are achieved.

In many of the case studies, the longevity of the benefits is also difficult to quantify. For example, Case Study 1 considers the avoidance of high spot prices. As highlighted in Section 3, small volumes of demand response could lead to a significant reduction in the magnitude of spot prices. Thus, in future years, the benefits of demand response are diminished, although of course, removal of the demand response would lead to a return of the peak prices. This would suggest that the business case is strengthened where a long term contract can be put in place to guarantee an income for a fixed period of time. However, securing long term contracts (i.e. of several years) in competitive markets could be particularly challenging.

9 Conclusions

This report concludes Task XIX of the IEA DSM Implementing Agreement. The previous report has identified the requirements and options for developing Micro Demand Response and Energy Saving propositions. This report explores the business case for demand response and energy saving products, particularly from the perspective of the Aggregator. Using a rigorous step by step approach, the report explores the following five case studies.

1: Dynamic control of electric heater loads for demand management, Finland
2: Dynamic response of residential heating loads, France
3: Energy efficient air-conditioning equipment, Greece
4: Mass installation of energy efficient lighting, India
5: Direct load control of commercial air conditioning, UK

The costs and benefits associated with deploying demand response and/or energy savings as a means of alleviating a specific '*problem*' have been evaluated. The '*problems*' considered include:

- the avoidance of peak spot prices;
- the avoided purchase of power from peaking generation plant
- minimising impact of regulated tariffs which have been set below the cost to supply; and
- the provision of reserve services.

Each case study explores the benefits and costs associated with targeting a specific end use i.e.'*target process*' able to deliver the demand response/energy savings required to alleviate the identified '*problem*'. The end-uses of energy that have been considered include:

- residential space heating (direct and storage);
- residential / commercial air-conditioning; and
- residential lighting.

In each case, the circumstances required to demonstrate a win/win/win situation for all participants (i.e. as listed below) is explored.

- the buyer (i.e. the organisation with a specific problem to alleviate);
- the customer (i.e. the provider of the demand response / energy savings); and
- the Aggregator (i.e. the facilitator of the process),

By considering specific case studies, it has been possible to identify the specific problem to be solved, and hence identify the potential range of benefits that can be realised. However, it is not always possible to quantify benefits over the long term. Whilst historic information and trends provide a useful guide, they do not provide a reliable indication of future income. For example, relatively small amounts of demand response could lead to significant future reductions in spot market prices. This would suggest that the business case would be strengthened where a long term contract can be put in place to guarantee an income for a fixed period of time.

In addition, there is a significant level of uncertainty surrounding the likely level of costs for the control, monitoring and communications technology required. As such, many of the case studies consider the likely range of benefits, together with a range of technology costs. The report also includes an analysis of the technology costs required to deliver a project with a zero NPV at the lowest and highest level of benefits, i.e. the breakeven technology costs. The results of this analysis indicate that, given the typical costs of control, monitoring and communication technologies, the viability of the business case requires that the higher level of benefits are achieved. Thus the role of 'future add-ins' becomes a critical element of the business case.

In the case studies considered here, only a limited number of potential 'future add-ins' have been considered. This is largely attributable to the specifics of the case studies identified, and suggests that better understanding of the interactions between market players could lead to greater opportunities for different service providers to offer innovative solutions.

Interestingly, smart metering is not an integral component of the case studies considered within this report. In particular, where smart metering is in place (Case Studies 1, 2 and 5), the Aggregator is assumed not to have direct access to the meter. Therefore in these Case Studies, dedicated external communications and communication gateway are required to facilitate any demand response activity. For example, in Case Study 1 (Finland) it is the DNO that is responsible for metering. As such, a Supplier or Aggregator has no opportunity to communicate directly with the meter. Conversely, where metering is the responsibility of the Supplier (as is the case in the UK), there is no opportunity for the DNO to communicate directly with the meter. Thus, in this situation, any DNO led aggregation scheme would not be able to utilise existing smart metering capability.

The issue of access to the smart meters is one that needs careful consideration. Maximising the benefits of smart metering may require multiple organisations to access the meter, and the data obtained by the meter. However, consumers need to have confidence over the way that their energy data is used, as well as who accesses their data. This is particularly critical given the key role that smart meters could play in the deployment of demand response. For example, plans to obligate the roll out of smart meters in the Netherlands have been revised due to privacy concerns raised by a consumers' organisation.

10 Recommendations

Whilst this report provides a good basis upon with the business case for demand response and energy saving products can be evaluated, it is believed this could be strengthened if the availability of end-use energy consumption data was improved, particularly in terms of the breakdown of end-uses within the SME sector and information on the time of use of energy by end-use category. Specifically, the analysis presented here is based on broad assumptions on the end-use consumption patterns of the various customer segments considered. Thus, as highlighted in Report 1, it is recommended that consideration be given to obtaining improved energy consumption data by end use, particularly in terms of the time of usage, for households and small to medium enterprises.

Although suitable technology exists for demand response and/or energy saving products, many of the case studies considered here require the development of application specific technology. Therefore, continued support of innovation in control, monitoring and communications technologies is recommended to facilitate the introduction of low cost technologies.

Interestingly, none of the case studies (in terms of the primary business case) relied upon the communications facility offered by smart metering. Whilst smart meters provide a gateway into the home for load control signals, the case studies have, in general, required the use of dedicated external communications and communications gateway. Given the widescale interest in smart meter deployment, and the associated cost of roll out, it is recommended that the role of smart meters in the deployment of demand response programs be considered carefully - especially in terms of the access of third parties, such as an Aggregator, to the smart meter.

Finally, the evaluation of any business model requires a detailed understanding of the environment within which it operates. As such, the interactions between the market players, which inevitably differ from market to market, is a key element in understanding the role of the demand Aggregator. This is particularly important where the Aggregator has the potential to impact on the relationship between a Supplier and its consumers. Therefore, it is suggested that further work is required to explore the role of regulation in facilitating the required interactions between key industry stakeholders such as customers, network operators, supply companies, metering businesses, demand side Aggregators and distributed energy resource operators. Such interactions are essential to ensure that the full benefits of demand response can be realised.

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Appendix 1 Technology Costs

Table A1.1 Example Technical Architecture Component Costs

Technical Architecture Component	Cost	Source
Visual display unit	£15 to £25+ (~€17 to €28+)	Low estimate based on mass roll out (Impact Assessment of Smart Meters for domestic consumers and for small businesses, April 2008) High estimate based on retail price of commercially available energy monitors such as the Owl, Efergy
Smart meter (automated meter reading functionality) – excluding display and communications	£17 (~€19)	Impact Assessment of Smart Meters for domestic consumers and for small businesses, April 2008
Smart meter (advanced meter management functionality) – excluding display and communications	£47 (~€52)	Impact Assessment of Smart Meters for domestic consumers and for small businesses, April 2008
Commercially available smart plugs / appliance control devices	£10 to £20 (~€11 to €22)	Products such as Picowatt, SmartAdapter, EcoSaver remote control socket kit
Internal communications system and communication gateway	£40 to £70 (~€44 to €77)	AlertMe Energy nano hub,
External communications	£25 to £36 (~€28 to €40)	Low estimate based on 75% broadband / 25% 3G. High estimate based on national radio network. Impact Assessment of Smart Meters for domestic consumers and for small businesses, April 2008
Complete smart meter deployment	£70 to £150 per meter (~€77 to €165)	Impact Assessment of Smart Meters for domestic consumers and for small businesses, April 2008 ENEL roll-out of smart meters to all 30 million consumers

Appendix 2 Generation Costs

The cost of new generating capacity is comprised of the following three elements:

- The capital costs, to cover the cost of the equipment, materials and labour required to build the plant;
- The financing costs that reflect the cost of interest and other charges involved in raising the capital required to fund the project; and
- The operating costs to cover the on-going costs of fuel, materials and labour to operate and maintain the plant.

The cost of new generation projects vary significantly, not only as a function of the generation technology employed, but also according to project complexity, regulatory costs and project management costs.

Table A2.1 highlights the capital costs of a range of generating technologies designed for baseload operation (i.e. with a load factor of 85%), taken from the Integrated Resource Plan for Connecticut, USA[47]. Also included, are details of operating and maintenance costs for these technologies.

Table A2.1 Generation costs for baseload operation (2008 prices)
Source: Connecticut Integrated Resource Plan

	CCGT	Supercritical Coal	IGCC	Advanced Nuclear
Capital cost ($/kW)	869	2,214	2,567	4,038
Fixed O&M ($/kW/yr)	29.7	47.3	59.2	102.9
Variable O&M ($/MWh)	1.4	5.8	7.6	1.8
Economic Life (years)	40	40	40	40

Baseload plant is generally considered to be more expensive to build than peaking plant, however the cost of each unit of electricity produced is lower, due to the higher load factor of baseload plant. Table A2.2 provides some typical costs of generation technologies more usually associated with peak load operation[48].

Table A2.2 Capital costs of peak load generation plant (2009 prices)

Technology	Capital Cost (£/kW)
Internal combustion engine	580 to 910
Combustion turbine	700 to 1,075

More recently, it was announced that two coal fired power plants were to be built in western India, each rated at 5 x 270MW. The project has been valued at 57.8bn rupees ($1.8bn)[49], which is equivalent to a capital cost of $480/kW. These costs appear to be much lower than those quoted in elsewhere, but may reflect country specific differences in capital projects, such as labour rates.

Further information on generation capital and operating costs can be obtained from the US Energy Information Administration, as summarised in Table A2.3

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47 Integrated Resource Plan for Connecticut, January 1, 2008, Prepared by The Brattle Group

48 Article available on www.renewableenergyworld.com entitled “How to compare power generation choices”, published October 2009 http://www.renewableenergyworld.com/rea/news/article/2009/10/how-to-compare-power-generation-choices

49 Article available on www.powergenworldwide.com entitled “Indiabull Elena Power awards major coal plant order to BHEL, published March 2010 http://www.powergenworldwide.com/index/display/articledisplay/3314437121/articles/powergenworldwide/coal-generation/new-projects/2010/03/indiabull-elena_power.html

Table A2.3 Generation Technology Costs (2007 prices) published by US Energy Information Administration

Technology	**Total Capital Cost(*) ($/kW)**	**Variable O&M Costs ($/kWh)**	**Fixed O&M Costs ($/kW)**
Scrubbed New Coal	2,058	4.59	27.53
ICGG (without CCS)	2,378	2.92	38.67
ICGG (with CCS)	3,496	4.44	46.12
Conv gas/oil combined cycle	962	2.07	12.48
Conv gas/oil combined cycle with ccs	948	2.00	11.70
Advanced combined cycle with ccs	1,890	2.94	19.90
Conventional combustion turbine	670	3.57	12.11
Advanced combustion turbine	634	3.17	10.53

(*) The total capital costs includes a contingency allowance and a technological optimisim factor. The contingency allowance, as defined by the American Association of Cost Engineers, is the "specific provision for unforeseeable elements if costs within a defined project scope; particularly important where previous experience has shown that unforeseeable events which will increase costs are likely to occur". The technological optimism factor is applied to the first four units of a new, unproven design (where applicable) to reflect the demonstrated tendency to underestimate actual costs for a first-of-a-kind unit.

Where demand response is considered as an alternative to investment in peaking power plant, the capital cost avoided will depend upon the type of technology employed. For the purposes of this study, it is assumed that advanced combustion turbine technology is used to meet peak load requirements, at a capital cost equivalent to $634/kW, based upon the data supplied by the US Energy Information Administration, as shown in Table A2.3. This represents the lower range of capital costs for new generation plant.