Subtask 3
Demand Side Bidding for Smaller Customers

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International Energy Agency Demand-Side
Management Programme
**Task XI: Time of Use Pricing and Energy Use for
Demand Management Delivery**

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IEA DSM REPORT - EXECUTIVE SUMMARY

TASK XI SUBTASK 3

DEMAND SIDE BIDDING FOR SMALLER CUSTOMERS

Background

Demand side bidding (DSB) is a mechanism enabling the demand side of electricity markets to participate in energy trading. Many countries are concerned that liberalised markets may not deliver adequate generation and network capacity. Greater participation of the demand side is a very important mechanism for addressing these issues and improving overall balancing of markets.

The domestic sector consumes between 20% and 40% of electricity in developed countries and is attractive for consideration of DSB. This report analyses and quantifies the potential and value of smaller customer DSB. Smaller customers willing to change demand can trade this activity with the help of demand Aggregators and be rewarded through reduced price for electricity or a direct payment. The process of DSB can provide benefits to System Operators, Suppliers and Customers. Changes in demand can result from customers actually reducing energy use, modifying times at which demand is taken or operating embedded generation. Verifying that individual customer demand has actually “turned down” in response to requests by System Operators or Suppliers uses time of use metering for larger customers. Smaller customers require other arrangements. Dynamic changes to smaller customer demand profiles impact “profile” settlement systems, and may require more complex arrangements.

Objectives

Demand Side Bidding is a process for formulating and delivering demand changes at customer premises in order to benefit System Operators, Suppliers and customers. It allows demand changes to be predicted, made to happen on a reliable basis and be built into schedules as alternatives to generation in meeting system demand. This study report addresses the feasibility and viability of DSB for smaller customers.

Approach

Mechanisms for enabling the demand side to participate in energy markets have been developed for larger customers in many countries. Customers participating in DSB are rewarded for making demand "available" and for implementing "turndown" when required. These actions require validation in order to be rewarded. The study has analysed requirements and mechanisms for validation of blocks of smaller customer demands and possible impacts of dynamic demand profiles on settlement systems. Analysis has been carried out into potential end use demands which could be aggregated and made available by customers. Consideration has also been given to payments made for demand "turndown" by smaller customers and possible costs of implementing automatic systems.

Results

In order to be effective, predictable and reliable, automatic demand changes are required by System Operators and Suppliers. The results of this study show that in principle, DSB for smaller customers could be implemented using available communication technology. However, more cost effective solutions are needed to enable bidding small demands to be viable in wide scale markets. Smaller customer demands between 0.5kW and 3kW per customer have been shown to be potentially "available" for aggregation. Targeting high demand, smaller customers using electric space heating and cooling, water heating and embedded generation is the most attractive starting point for DSB cost effectiveness. Refrigeration and lighting are also shown to be attractive targets for DSB implementation.

Implications

This study has shown that in principle, DSB for aggregated smaller customer demands is technically feasible and would contribute significantly to system management. However, a number of areas of further study have been identified. Progress in these areas will assist in moving DSB for smaller customers closer to reality. These areas are :-

- Quantify the extent to which smaller customers are prepared to bid specific end use demands and the motivators needed.
- Develop cost effective mechanisms and processes for aggregating smaller customer demand, validating demand “available” and validating demand “turn down”.
- Quantify the impact of smaller customer, dynamic profiles on “profile” settlements systems.

Contents

1 Introduction

Many countries are concerned as to whether of adequate generation capacity will be provided in liberalised markets and consider greater participation of the demand side a means for addressing the issue and improving overall efficiency of markets.

Demand side bidding (DSB) is a mechanism enabling the demand side of electricity markets to participate in energy trading. Maintaining the balance between supply and demand, and maintaining quality and security of supply are the responsibility of System Operators. Generally this is achieved by calling on generators to bring additional plant on-line at times of difficulties. DSB enables electricity customers to offer specific changes in demand, at given points in time, in return for specific rewards. This provides an alternative to generation, by calling on customers to make load reductions. Almost always, reserve generators are less efficient, and produce higher CO_2 emissions, than base load plant. There is also an added energy penalty in starting them up and holding them in a state of readiness. DSB can thus be regarded as a means of optimising overall system energy efficiency, by reducing the need for such plant.

Customers are rewarded for having the flexibility to make short-term, discrete changes in demand, which help deliver secure and reliable electricity supply systems.

Demand side buyers are essentially purchasers of demand side bids. Such purchasers are involved in wholesale electricity markets and need to balance electricity supply and demand or maintain quality and security of supply. In particular, electricity Suppliers, Generators, System Operators, Energy Service Companies (ESCOs) and Network companies are all potential demand side buyers.

Customers willing to assist demand side buyers are rewarded either by a reduced price for purchase of electricity or by direct payment for actually changing their demand.

DSB implies ownership by customers of the right to consume a given amount of electricity at a given time. This right is traded by reducing demand; in effect selling the reduction in demand.

The domestic, smaller customer sector consumes between 20-40% of electricity in developed countries, and is an obvious and attractive candidate for consideration of DSB. This report concentrates on defining the potential and implementation mechanisms for smaller customer demand participation in electricity markets.

Smaller customers need the services of demand Aggregators in order to participate in markets. Aggregators of demand side bids have an important, perhaps fundamental, role in the implementation of successful DSB schemes for smaller customers because purchasers of DSB specify minimum demand block sizes which can be used. This is usually several MW. In order for Aggregators to have sufficient incentive to become involved, the income derived from DSB needs to more than offset the costs incurred in setting up bidding schemes.

Energy demand for smaller customers is elastic if appropriate incentives and motivators are put in place to make it happen. The critical issue is whether the elasticity can be utilised by means of cost-effective incentives. Benefits result from both reducing actual energy usage through participation in conservation measures, moving demand from high to low price periods and bidding actual programmed demand reductions and embedded generation at specific times into the market to support central generation, network shortages or balancing contracts.

Motivators for potential customer participation are:-

1 Environmental concern (CO_2 saving) and saving money from reducing energy use
2 Saving money and helping environment as a result of peak capacity reductions
3 Being paid for “availability” and implementing demand “turndown”. Start up of embedded generation to shift demand from peaks. Reducing the need for generation capacity, possibly reducing energy use, increasing system security and contributing to system balancing.

Engaging smaller customers in energy saving measures in response to market forces and signals requires a combination of technical and marketing drivers. The main technical challenge is the provision of cost effective communication and control technologies to activate and monitor demand changes for large numbers of small consumers. Nearly all energy saving actions implemented by smaller customers incur some minor inconvenience or negative impact on their lifestyle. Consequently, market drivers for behaviour and energy use changes need to be very obvious and/or applied automatically to end use applications and demand. A major difficulty in motivating end use change is understanding the end uses of energy at specific customer premises. Another important factor is to understand the potential for change in end use behaviour and the willingness of customers to participate in response to stimuli. This requires powerful motivating messages to be in place which are generally accepted, at least in principle, by customers.

Many countries have implemented competitive markets for energy where residential and small commercial and industrial customers are able to choose their energy supplier without the requirement for time of use metering. In these cases, the time of use metering process used for larger energy users is replaced by “profile metering” for smaller customers. This “profile metering” allows energy suppliers to buy energy in the wholesale market based on time of use and account for its use by smaller customers on an estimated “time of use" basis. "Profile metering" offers some of the benefits of time of use metering but at lower cost. However, the use of "profile metering" (as presently implemented) removes any incentive for customers to modify the shape of their energy demand curve.

Verifying energy demand curve changes which result from DSB implementation usually requires time of use energy monitoring. Dynamic changes to smaller customer demand profiles in response to price are difficult to deal with using existing "profile" settlement systems, and possible solutions are considered in Chapter 7.

This study report addresses the feasibility and viability of DSB for smaller customers.

2 Bidding Demand Side

2.1 Markets for DSB

Demand Side Bidding is a process for formulating and delivering demand changes at customer premises in order to benefit System Operators, Suppliers and customers. It allows demand changes to be predicted, made to happen on a reliable basis and be built into schedules as alternatives to generation in meeting system demand.

Some countries operate Balancing Markets to ensure that the amount of electricity generated exactly matches the demand at all times. These markets are generally managed by System Operators. If generation is not sufficient to meet expected demand, System Operators can accept bids from generators to increase output. Alternatively, they can accept bids from customers to reduce demand. The cost of meeting these imbalances is determined by the terms of the bids offered by generators, suppliers and customers.

Balance responsible parties including usually larger customers, generators or suppliers are exposed to prices in the balancing market. Demand side bids can often be effectively traded alongside generation bids in balancing and standby markets.

There are a number of markets and trading mechanisms in competitive electricity markets for obtaining generation and demand side bids across a range of durations and notice periods. Scheduled time frames associated with different DSB categories are shown in Fig. 1. Here each bid is allocated to one of three main time frames, with the different periods defined as 'months ahead of trading', 'day ahead of trading' and 'within day trading'. The within day trading time-frame can be between several hours to 15 minutes ahead of delivery or immediately at the time of delivery. In some markets, the 'spot' market closure coincides with the end of the day ahead of trading. However, there is a tendency, as markets develop, for this to get closer to the point of delivery.

With few exceptions, the following model applies to the whole Nordic market.

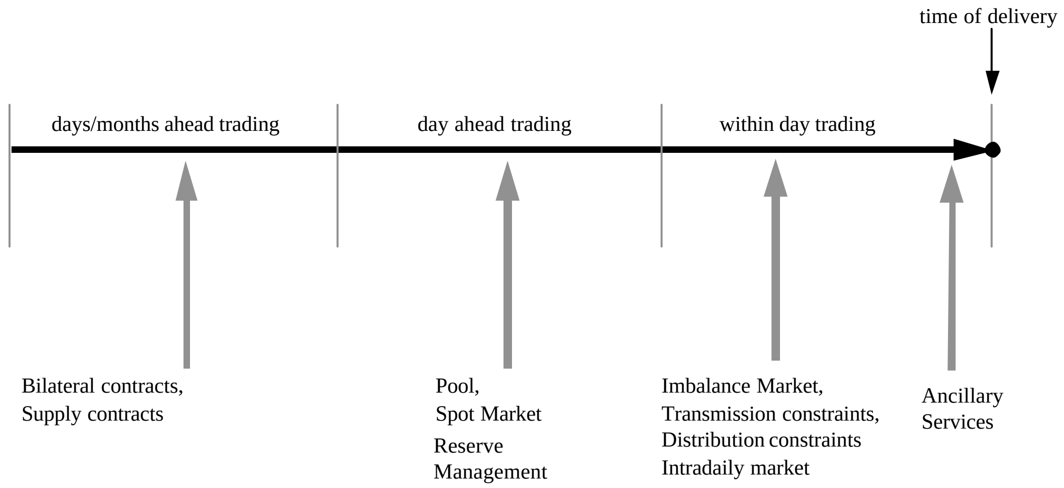


Fig 1 Timescale for bids for different DSB products

Countries with liberalised electricity markets have demand side products available that fall into most, if not all, of these time frames. These products are used in the following applications:

DSB to maintain quality of supply	- Ancillary services (various types)
DSB to solve network constraints	- Distribution constraints - Transmission constraints
DSB for electricity balancing	- Balancing markets
DSB for access to market prices	- Spot markets

DSB to maintain quality of supply – Ancillary services

Control	DSB Frequency and Voltage Ancillary Services involve instantaneous load shedding. Therefore, the control mechanism must be in the form of an automatic switch that turns off the load to a particular circuit when the voltage or frequency reaches specific limits. For most industrial processes, it is possible that switching the load back on must be done manually due to start-up procedures. In which case, it is not necessary for the control mechanism to be able to switch on the load, but it should include some form of notification mechanism that informs customers when they can switch the load on. DSB for reserve may be given a few minutes notice, although control may still be automatic.
Settlement & Monitoring	It is likely that customers will be paid a fee for times when they make demand "available" to provide DSB Ancillary

	Services. Monitoring may be required to prove that load was “available” and that it was “turned down” in the agreed manner.

DSB to solve network constraints

Control	DSB Network Constraint contracts are most likely to be called upon in the day of actual “turndown”, usually in the few hours ahead of the relevant trading period. Nevertheless, there is likely to be sufficient time for customers to plan the necessary load switching that is associated with an accepted bid. This suggests that manual control of the relevant electrical circuit may be sufficient, although some form of automatic control mechanism is preferable. An automatic controller may take the form of a programmable device that ensures no load is taken on the relevant electrical circuit during the time a particular “turndown” is in place.
Settlement & Monitoring	It is likely that customers are paid a fee for times when they make demand “available” to provide DSB Network Constraint services. This is an attractive approach because it is simple to administer. However, the Network Operator (Distribution or Transmission company) may not favour this payment mechanism because a predicted constraint will not always turn out to be an actual constraint. Thus, according to this method a company would be paying for a service they do not actually require in some time periods. Therefore, it may be more appropriate to pay customers for each “turndown. If this approached is implemented, only a simple form of monitoring is required that registers the number of interruptions within a specific time period. However, if customers are paid according to the length of each interruption then more complex metering may be necessary.

DSB for Electricity Balancing

Control	DSB Balancing Market contracts are most likely to be traded from a few hours to 15 minutes ahead of the relevant trading period. Nevertheless, there is likely to be sufficient time for customers to plan the necessary load switching associated with an accepted bid. This suggests that manual control of the relevant electrical circuit may be sufficient, although some form of automatic control mechanism is probably preferable. An automatic controller may take the form of a programmable device that ensures no load is taken on the relevant electrical circuit during the time a particular bid “turndown” is in place.
Settlement & Monitoring	Customers are likely to be paid according to the quantity of load they do not consume, perhaps as a price per kilowatt-

	hour. Therefore, in order to ensure a consumer fulfils their contractual commitments some form of ‘avoided’ consumption monitoring is necessary. In addition, a means of proving that the consumer would normally have taken that load during the “turndown” time is also required. The appropriate metering solution for this task will vary depending on the size of the customer, but it is likely to be either time of day, half hourly or minute-by-minute metering.
Communication	Notification that a bid has been accepted for balancing purposes may be provided by several different communication methods.

DSB for access to market prices

Control	DSB Spot Market contracts are most likely to be traded ahead of the day of actual bid delivery. Therefore, there is sufficient time for customers to plan the necessary load switching that is associated with an accepted bid. This suggests that manual control of the relevant electrical circuit may be sufficient, although some form of automatic control mechanism is probably preferable. An automatic controller may take the form of a programmable device that defines the required load profile on the relevant electrical circuit during the day of actual trading.
Settlement & Monitoring	Usually time of day metering will be required (e.g. half-hourly)
Communication	Customers will receive details of the agreed pricing information just ahead of the day of consumption, by telephone or dedicated communication media. Communication within customer premises (e.g. main signalling or dedicate control wiring) is likely to be required to effect the calculated load profiles.

Customers can bid demand into markets in similar ways to that undertaken by generators. In these schemes, customers bid how much demand they will not consume for a given price, at a given time, and generators bid how much electricity they will generate for a given price. This results in two price-demand curves, as shown in Fig 2. One is a generation curve showing the increase in generation costs with increased demand and the other is a customer curve showing reduction in demand in response to increased price. The point at which the two curves intersect determines the contract price.

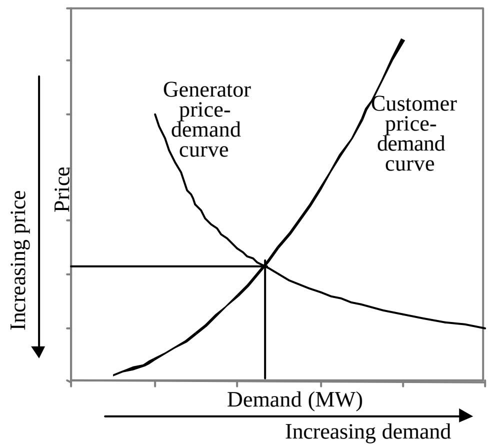


Fig 2 Price-demand curve

The requirements for bidding demand into markets for generation are that the actual demand blocks which would normally have been consumed are made "available" not to be consumed because the payments or motivator is attractive to the customer. Consequently the demand elasticity identified in response to TOU pricing or fixed fee pricing and resulting profile shape change in "shifting" demand can be mobilised at the request of System Operators. The demand "turndown" would be bid into the market for use by Market Operators or System Operators as an alternative to dispatched generation. The demand profile shape could be changed as a result of starting embedded generation in response to a "turndown" request. This is a valid bid for participation in the market with the predictable demand reduction as seen by System Operators being the important parameter.

The System Operator in the UK purchases various services that can be called upon to respond to a sudden loss in system frequency. The initial response is fast acting and lasts from 30 seconds (for a primary generator response) to up to 30 minutes for secondary responses (including Demand Response automatically activated by low frequency relays). The System Operator then calls on other services to help the system recover. Typical reaction times and durations are shown in Fig 3 for the range of services required.

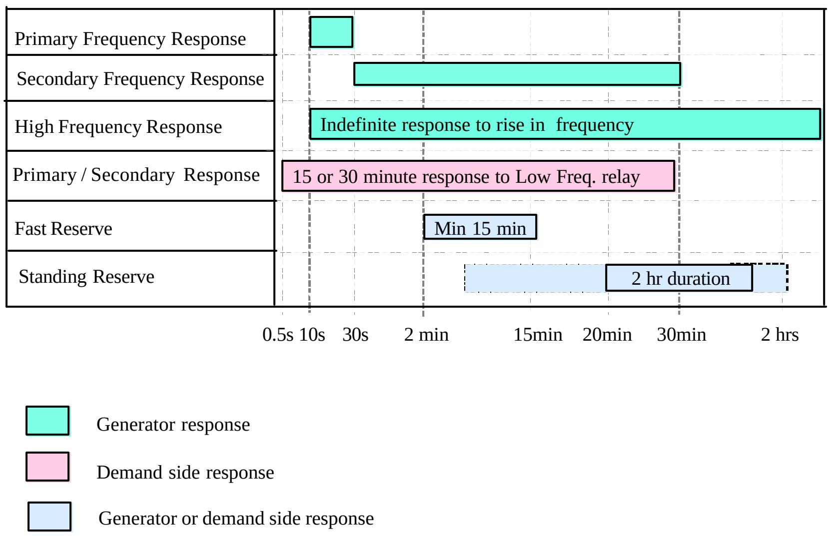


Fig 3 System Operator Response Time Requirements

For customers to be able to provide frequency response services to the UK System Operator, they must be able to offer at least 3 MW of demand which can be reduced instantaneously (i.e. automatically).

The System Operator also purchases standing reserve. This is provided by both generators and the demand-side. It requires a time to respond of between 5 and 20 minutes, and must be capable of being sustained for at least 2 hours.

The need for standing reserve is a function of system demand profile, and varies across the year, the time of week and time of day. To reflect these variations, the System Operator splits the year into five seasons, for both working and non-working days, and specifies the periods in each day when Standing Reserve is required. These periods are referred to as Availability windows,

For a bid to be accepted by the System Operator, the Standing Reserve must be available for at least three periods of each week, Fig 4.

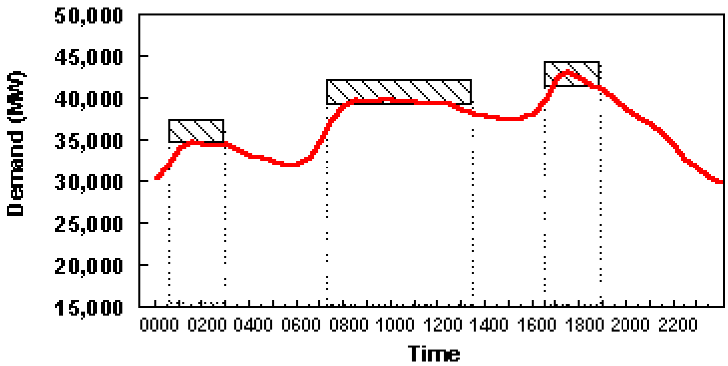


Fig 4 Typical times of the day when Standing Reserve is required

Norway's Power Reserves Option Market includes a number of successful Demand Side products. The market allows the demand side to assist the System Operator in ensuring demand and supply are in balance. This is becoming increasingly difficult due to the lack of investment in new generation capacity. Although participation is restricted to customers able to offer at least 25 MW of demand reduction, it has been successful in securing demand side bids. The demand side provided approximately 1300MW of bids during the winter of 2001/2002, compared to 600MW from generation.

Demand Side Bidding Schemes are also in place in Nordic countries and Netherlands.

In Spain, no DSB mechanism is implemented in the market. One daily and several intra-daily markets allow generation/consumption transactions and matching, and a "deviation market" can be called any time when deviation between forecasts and real consumption is too high. Nevertheless these markets, which are quite similar to “balancing markets” and which could be used to reduce demand via DSB, respond to technical criteria from the retailers (distributors and commercial companies) which prefer to adjust their purchases according to real-time consumption rather than pay for more expensive deviations.

The Danish market is an integral part of the Nordic market and is based on the following principles:-

- Before the hour of operation (in practice 12 hours before the day of operation) in Elspot market or one hour before the operating hour in Elbas market):-
    - Customers through their Suppliers trade with producers to cover their consumption hour by hour for the next 24 hours.
    - The market is divided among a number of balance responsible parties balance holders. They can be Suppliers, power companies or large customers.
    - Each balance holder is responsible for balance between energy contracted by customers and the energy contracted for delivery.
    - Each customer has only one balance holder of which eighteen are active in Denmark at the present time.
    - The balance holders report their demand to the System Operator who checks if the schedule can be implemented or needs correction.

- During the hour of operation:-
    - The System Operator takes responsibility for the system being in balance. If this is not the case, any discrepancy in energy is purchased in the regulating power market. If consumption is lower than reported, purchases will be made from a balance holder (or at least in Finland from other participants of the regulating power market). The actual consumption is metered by the grid companies.

- After the hour of operation (in practice the day after the day of operation):-
    - The metering of consumption and production are collated.
    - Actual consumption and production always deviate from planned values but do not change the trades concluded the day before.
    - If more has been consumed than purchased, the difference is bought by the System Operator, if less, the surplus is sold to the System Operator.
    - Metering is not used to settle the commercial trades, but to settle the imbalances.

Suppliers can benefit from market participation of the demand side. Customers willing to reduce demand, assist Suppliers in three ways:

- Enable Suppliers to avoid high market prices for top up electricity (i.e. one customer/group of customers reduce their demand in order to that the demand of another customer/group is satisfied).
- Enable Suppliers to 'make money' by selling electricity back to the spot market when prices make such actions favourable.
- Enable Suppliers to avoid imbalance charges if one customer/group of customers require more electricity than expected at the time of gate-closure on the spot market, which can be up to 36 hours before the time of delivery.

A critical factor in the acceptability of DSB schemes by customers is how often and for how long a DSB "turndown" is required in order to be valuable to System Operators and Suppliers. If DSB implementation takes place, during peak system demand times, then an indication of these values can be obtained from system load duration curves.

In the UK, a market survey showed that the maximum demand in England & Wales during the financial year 1999/2000 was 51.4GW. However, the system demand only exceeded 90% of this peak for fewer than 160 hours during the 12 month period (i.e. for less than 2% of the year), and only exceeded 95% of the peak demand for less than 24 hours. A similar situation exists in Norway, where the demand only exceeded 90% of the maximum during 2001 for less than 2% of the year.

In Spain, Fig 5, the last 2000 MW of generation to meet system maximum demand only operated for 9 hours in 2004.

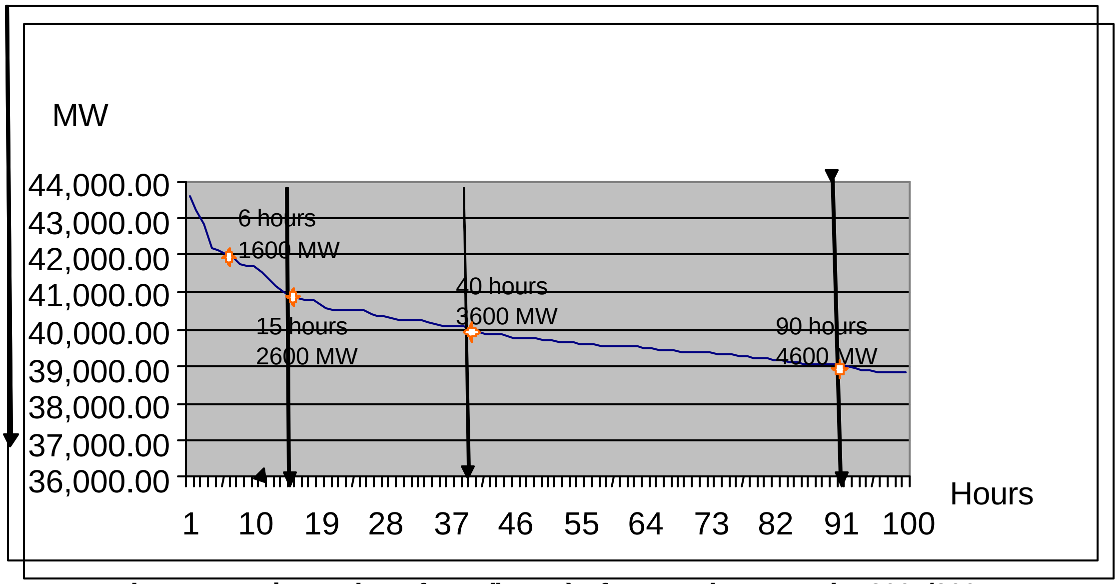


Fig 5 Annual Duration of use (hours) of generation capacity 2004/2005 (maximum 100hours)

2.2 Larger Customer Participation in DSB

Mechanisms for enabling the demand side to participate in energy markets have been developed for larger customers in several countries. System Operation in some countries is being set financial targets as regulatory measures in order to reduce system operation costs and this is likely to encourage participation of demand side in the market.

In Sweden, two market problems have been addressed by using demand side projects. There is a risk of a lack of generation bids on the Nord Pool Spot. The possibility of lack of capacity on the Spot market in extreme peak load situations led to the "Industribud" project. This developed a model for making demand bids available on the Spot market. Another project deals with the System Operator's need to secure peak load capacity on the balancing market. These projects are carried out in accordance with a temporary law which gives the System Operator the task of purchase up to 2000MW of capacity exclusively for situations when the voluntary bids on the balancing market are inadequate. Both projects are directed to larger customers (above 10MW). "Industribud" promotes commercially viable demand reductions for industrial plants and facilities. The System Operator capacity reserve acquisitions invites demand reductions to be incorporated in capacity reserves for peak load situations. In "Industribud", which is voluntary and flexible from one time to another, any larger customer can participate, but the campaign was mainly targeted at industrial facilities with an average demand of 10-15MW or more. The basis of "Industribud" is a contract between customer and Supplier and implies that both parties can benefit from the demand side actions that the customer performs. Basically, the Supplier incorporates bids from customers in his bidding on the Spot Market. Requests are communicated after the Spot closure, which is well ahead of actual "turndown" time. The conditions of the "turndown" depend on what limits have been agreed between each individual customer and their Supplier/Aggregator. Contact is established by telephone.

The other project is the System Operator capacity reserve. In Sweden companies contracted to the System Operator capacity reserve are obliged to provide the contracted capacity when requested. A contracted industry receives a fixed sum for being available during December to February and then a "turndown" fee which is agreed in the contract.

Up to now, only one Aggregator has entered the program. Aggregators collect contracts for capacity from several customers of 1-2 MW and are responsible for delivering the agreed capacity for the use by the System Operator.

"Available" demand is the load that would normally be in use, but which is reduced during times requested by the System Operator. It is expected to be "available" with as high reliability as generation capacity reserves. The use of statistics is included to define the demand "available" from which validation of actual reductions are calculated post event. This requires the normal load curve/profile to be compared with the actual load during the period of "turndown".

Each customer/location has to be validated for the total "available" load reduction to be secured. Minor deviations from what has been agreed are accepted by the System Operator, but generally each customer has to deliver what they have promised to deliver.

Each customer can choose individually the time frame for demand response that they offer. The basic criterion is that the customer must be prepared for demand reduction in a 48 hour period. Faster response is appreciated by the System Operator and receives a higher payment for "availability" and a higher "turndown" fee.

Other countries have similar processes which operate through contracts agreed between System Operator and customer or demand Aggregator. These contracts are structured in such a way that levels of demand change at specific times and for specified durations are committed by customers in some future time period. Payments by System Operators to customers are made following the successful "turndown" of demand. Validation of the demand "available" for change and of the change actually carried out, "turndown" uses a process of time of use metering and pre and post event comparison of customer demand profiles. This process works well for large customers. In order to be valuable to System Operators, demand blocks of many MW are required to be "available" for change. Markets in particular countries vary in terms of the required demand block size. However, overall these blocks range from 100 MW down to 5 MW. In some countries aggregation of demand is also carried out for medium sized customers equipped with TOU metering. This aggregation works on the basis that contracts are put in place between System Operators and demand Aggregators. Aggregators have separate contracts with customers regarding the demand changes that are bid and the times and durations permitted. The process is implemented by System Operators calling on Aggregators to "turndown" demand at agreed times. The demand change is made by Aggregators from a portfolio of customer demands "available".

Customers participating in System Operator demand bidding schemes organise their processes so as not to be remotely disabled in the middle of a production process or similar. They still need to be in control to make sure that everything works out right.

2.3 DSB for Smaller Customers

In order to implement "turndown" of managed demand to smaller customers (domestic and small businesses without TOU metering) remote disabling of end uses is likely to be the preferred option. However, motivating smaller customers to participate will require extensive information campaigns. Simplicity of application and participation need to be accompanied by adequate reward.

The financial benefits for smaller customers are likely to be limited if savings in the total cost of energy by reducing load in peak price periods, is the only parameter. Once more sophisticated equipment for load management and/or metering is installed there will be other savings to be made because customers will become more knowledgeable and consume energy more optimally with regards to time of use.

Some Demand Side Bidding participation for smaller customers can be carried out with only minor changes to lifestyle by using technology and equipment available for doing load adjustments pre-programmed for real-time responses to high prices or direct switching signals. The most common way of reducing load is to not use electric space or hot water heating systems fully during high cost times. There are also some other end uses that may be acceptable to inhibit.

In practice, it is not feasible for smaller consumers to offer DSB in electricity wholesale markets because the administrative costs and complexity are too high. If customers and their reductions in demand are to be fully metered, (real time, hour by hour), the investment will exceed €100 per customer. In order for smaller customers to engage in DSB, the services of a demand Aggregator are required. Aggregators facilitate DSB among many smaller customers by combining bids together to form a major bid that can be traded in the wholesale electricity market. In addition, Aggregators can be responsible for ensuring each demand bidder has the appropriate control and monitoring equipment in place to fulfil their bid. In practice, any organisation can act as a demand Aggregator. However, it is a role that can be attractive to electricity Suppliers and also to Energy Service Companies (ESCO). ESCOS can also help customers to search for a Supplier offering the best deal and reward to reduce imbalance costs.

In order to estimate the potential for bidding the demand of smaller customers into markets, it is necessary to understand the flexibility of individual end uses. It is also necessary, in order to facilitate demand side participation by smaller customers, to identify and develop mechanisms and methodologies which allow their demand to be aggregated, validated as "available" and validated as "turned down" following a request. This requires validating that the demand actually bid would normally have been consumed at the time offered and is therefore "available" not to be consumed at that time. Validating that the demand has not actually been consumed at the time of "turndown" following System Operator requests is also required. To validate "turndown" carried out by an Aggregator, the sum of consumption at all contracted customers has to be compared to a normal profile.

In general, smaller customers use total volume metering without TOU definition. (Storage space heating and water heating use two rate metering and remote switching in some countries). Individual validation of demand "turndown" for aggregated smaller customers is impracticable unless some automatic process is used which inhibits the use of some specific end uses of energy during "turndown" periods. A statistical delivery of demand "turndown" validation could be acceptable with individual customers not validated and all customers rewarded for registering to take part in DSB. This reward could be via the tariff. Smaller customers could receive different levels of reward depending on the types and number of end uses made “available” for DSB participation.

2.4 Summary of Demand Side Bidding

Many field trials and DSB implementations have been carried out in participating countries to establish a real and dynamic market for DSB products. Almost all of these implementations involve larger customers although some do involve the use of Aggregators. Finland has several DSB products which respond to Fast Reserve, Balancing market, Supply Contracts, customer owned diesel generators and large electric boilers. These products and markets have notice of delivery timescales which range from immediate delivery (no notice) to many minutes, based on telephone calls. Spain has products in the Energy Trading and Balancing markets and interruptible tariffs which have notification times ranging from 24 hours ahead to a few minutes. Sweden also has products in use in the Balancing and Spot markets. These have notice times ranging from less than 1 hour to 36 hours. The UK also has services in use based on the provision of DSB and Ancillary Services. These products are used for Trading, Frequency control, Standby reserve and Transmission constraints. Notification times before implementation range from instantaneous to 12 hours. Countries generally specify the minimum size of demand bids which can be included. These range from 1MW upwards. Countries also define the maximum number of occasions per annum when demand bids will be implemented and demand reduced. These range from “no limits” to 30 times per year. In practice a “few times” per year is usual. Duration of demand reduction implementations range from 15 minutes to “no limits” although the longest defined time is 12 hours.

All these parameters are agreed in contracts between System Operators and customers or Aggregators so that for specific DSB applications, the delivered reductions in demand are tightly specified and the rewards adjusted accordingly.

3 Smaller Customer “Available” Demand

Demand Side Bidding is the formalisation of demand changes which can take place and already do so in many countries in response to TOU price or other signals to customers. Demand Side Bidding involves the use of contracts between buyer and seller of demand changes so as to guarantee delivery of the demand “turndown”.

Chapter 2 mapped out the parameters for flexibility of blocks in order for them to be valuable to System Operators. Smaller customer demand has significant potential to be included in Demand Side Bidding. This is through the use of Aggregator businesses to collect sufficient customers and demand with the appropriate “turndown” parameters to meet minimum demand block sizes and the requirement of System Operators. The potential demand available at smaller customers’ premises requires appropriate rewards to be made available and suitable technology installed in order to be effective. This topic has been studied extensively in Subtask 2 report, “Time of Use Pricing for Demand Management Delivery”, where customer response to Real Time Pricing was evaluated. This was carried out by considering three TOU pricing regimes against which the potential for changing customer behaviour and demand were estimated. These regimes were “Tariff TOU Pricing” where customers pay either a fixed but reduced energy tariff for possibly allowing remotely managed demand charges. “Dynamic TOU Pricing” where customers pay a changing or a fixed price energy tariff for energy with possible remote switching of demand based on a period of notice. “Real Time Pricing” where customers pay either a changing or fixed price for energy with remote/automatic switching of demand based on minimal notice periods.

The Subtask 2 study considered a range of demand change activities which could be used in principle to deliver DSB. These potential end use demands have a range of response times for delivery of “turndown”.

- Storage space heating and cooling and water heating (switch energy “in”/“out” instantaneously available)

- Direct space heating (modify thermostat settings) – notice period and duration required before available

- Direct water heating (modify thermostat settings) notice period and duration required before available

- Direct space cooling (modify thermostat settings) notice period and duration required before available

- Embedded generation (start out of heat led regime is switch “in”/“out”) instantaneously available

- Fridges and freezers (switch off for short period switched “in”/“out” with auto switch “in”) instantaneously available

- Washing machines (disable for period, change time schedule) notice period and duration required before available

- Cooker (disable for period) notice period and duration required before available

- Sauna, car heaters (disable for period) notice period and duration required before available

- Direct electric showers (disable for period) notice period and duration required before available

- Lighting (reduce for period) switch "out" with auto switch "in" instantaneously before available

When considering whether and how these potential demand changes be used for DSB, the role of the Aggregator becomes very important as the business driver for acquisition of usable customer demand and making investment for delivering DSB and "turndown".

The Aggregator will bear the costs of:

- Installing communication technologies
- Interfacing with standby generator controls
- Installing and / or remotely reading meters where required
- Submitting tenders

The Aggregator income will be a share of the "availability" and "turndown" payments or, in the case of Supplier as an Aggregator, also a reduction of the electricity purchase bill from the wholesale market).

3.1 Conclusions of Subtask 2 Smaller Customer, TOU Pricing Motivator Study

- Reducing peak demand for few a hours per year has large benefit

- Tariff, Dynamic and Real Time TOU pricing are viable for direct space, water heating thermostat control

- May be viable for central air conditioning, microgeneration, saunas and direct electric showers

- May be possible to inhibit demand for short times for each smaller customer but apply to larger population in sequence

- Communication not major technical constraint

- Dynamic and Real Time TOU demand switching can replace scheduled generation

- Customers prefer automatic rather than manual switching based on price.

3.2 Availability of Biddable Demand

In order to evaluate the potential for bidding elements of smaller customer demand into different markets, discrete end uses of energy need to be considered. Subtask 2 used smaller customers disaggregated end use demand contributions to system peak in Spain in order to quantify the value of managing the demand of individual uses of electricity by smaller customers.

Smaller customer average contribution to system peak demand and therefore potentially "available" was shown in the Subtask 2 report to range from 0.56KW (Spain) to 3KW (Finland) depending on whether electric heating was used in the specific country.

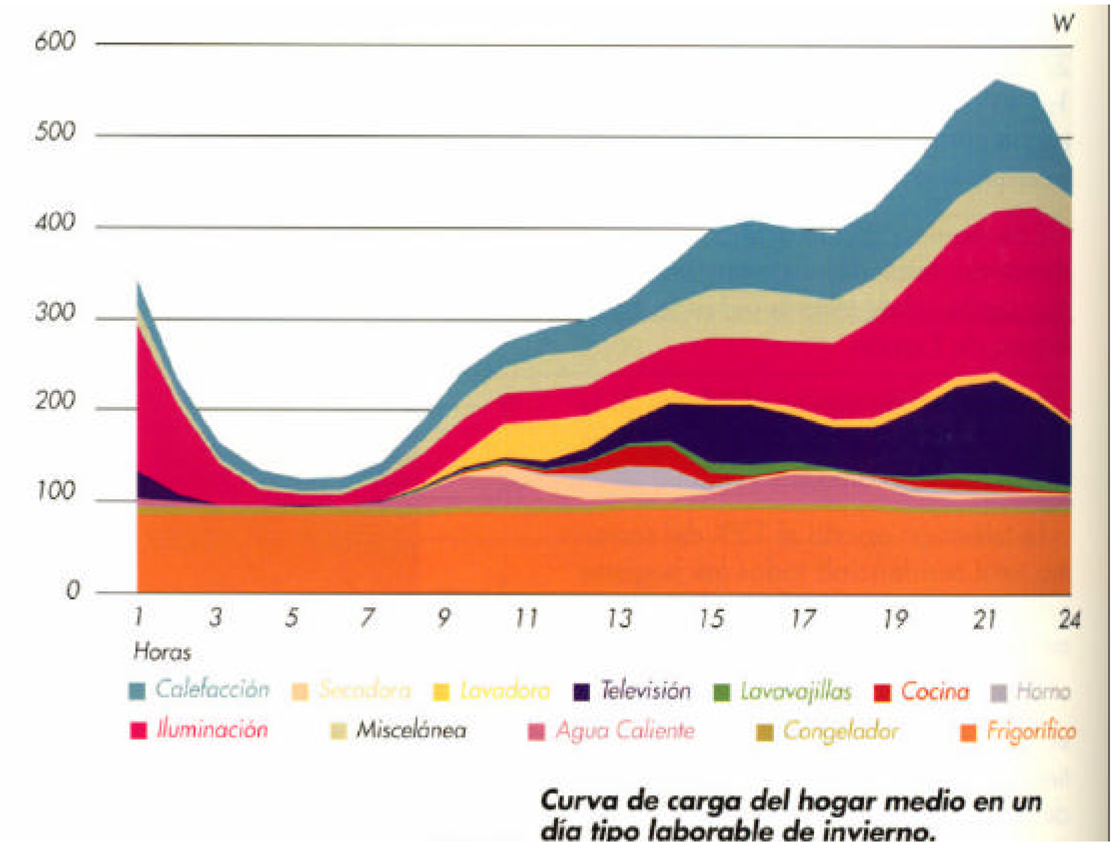


Fig. 6 Smaller Customer Individual End Use Contribution to Peak Demand in Spain

This curve shows demand contributions from :-

Spanish	English	Impact of DSB	ADMD
Calefaccion	Space Heating	Non obtrusive	130 watts
Lavavajillas	Clothes Washing	75% obtrusive	
Secadora	Tumble Dryer	75% obtrusive	
Television	Television	100% obtrusive	100 watts
Lavadora	Dishwasher	75% obtrusive	
Cocina	Cooker	100% obtrusive	
Horna	Oven	100% obtrusive	
Illuminacion	Lighting	50% obtrusive	200 watts
Miscelanea	Miscellaneous		
Agua Caliente	Water Heating	Non obtrusive	
Congelador	Freezer	Non obtrusive	
Frigorifico	Refrigerator	Non obtrusive	100 watts

Fig 6 and associated table show the contribution of different household energy end uses to system peak in Spain.

Against each of these end use demands is an indication of the level of obtrusiveness resulting from their "turndown" as well as the diversified demand contribution of each.

The table also shows that space heating, lighting and refrigeration (fridges) contribute 75% of smaller customer demand (0.43kw) to system peak. "Turndown" of these demands has been considered to be relatively unobtrusive if some advance warning were provided in selected cases to customers. Television is a significant contributor to maximum demand but is classed as any attempt at management being very obtrusive. The 75% figure will vary greatly for different countries depending upon climate and the amount of direct electric heating used. In Scandinavia, significant quantities of direct electric heating are used whereas in the UK mainly all houses are heated by gas with approximately 10% heated by off peak storage electricity. DSB and management of this storage demand which consumes electricity in off peak times, would allow peaks in demand during normally off peak times to be dealt with.

Perhaps 80% to 90% of electrically heated houses ADMD could be classed as relatively unobtrusive (2.5kW), i.e. customers are unaware of the demand management taking place generally because of storage or thermal inertia.

The degree to which smaller customers would participate in obtrusive and non obtrusive automatic demand changes and "turndown" of end uses is not known. It is likely that with appropriate promotion regarding environmental benefits, together with modest payment, that non obtrusive demand changes would be accepted by many customers. Obtrusive demand changes involving white goods "turndown" and inhibits would be much more difficult to sell to smaller customers. Lighting is a valuable energy end use in terms of automatic demand reduction potential because it contributes significantly to system maximum demand. Its "turndown" would be relatively obtrusive in the sense that customers would know it had been reduced but it may not cause much inconvenience if the reduction was limited in magnitude and duration.

Collecting and aggregating smaller customer end use demands having specific "turndown" parameters will require a communications infrastructure.

4 Field Trials and Implementations of DSB

4.1 Demand Side Bidding Project in Denmark

A pilot project on DSB offered by households has been carried out by two System Responsible grid companies in Denmark, Eltra and Elkraft in the spring of 2003, to be completed in the summer of 2004. The project is part of the EU EFFLOCOM project

25 single family houses with direct electric heating have been equipped for remote control (turn on and off) of their heating. The installation in the houses comprised a special meter, relays and communication with the System Operator. Customers communicate with the system by Internet, with the choice of setting limits for the maximum duration of interruptions for up to five control zones in the house (e.g. water heater, bedroom, kitchen, sitting room) and for different periods of the day.

Customers were able choose between three different bonus rates for each kWh "turned down". It was also possible to stop an actual interruption for some or all of the control zones. On the Internet, customers could see daily, weekly and monthly use of electricity and reward for participating in demand "turndown". Fig 7 illustrates the variables controllable by customers.

User preferences

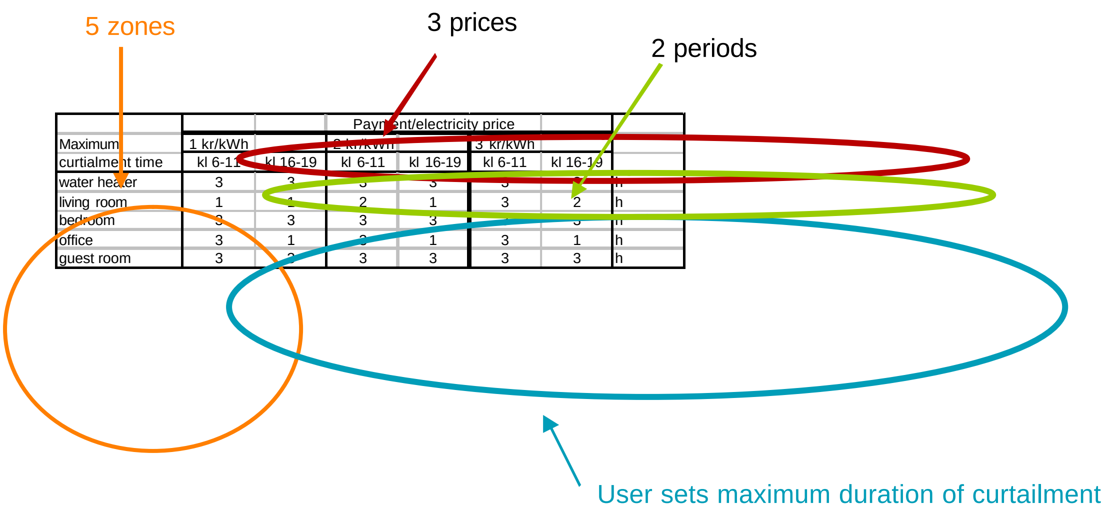


Fig 7 Customer Defined Variables in Bidding Demand

From preliminary conclusions, the following can be identified:

- It is possible to reduce demand on request or instruction.
- A facility, where interruptions can be stopped in case of inconvenience, is important.
- Differentiation in reward payments and maximum durations of interruptions for different control zones is not so important or maybe too complex to use.

- Only 50% of the interrupted power is used afterwards to bring the temperature back to the required level. This indicates a true saving of energy.

- The pilot project did not produce sufficient information to directly calculate figures for the demand response elasticity. (That was not an objective of the project).

4.2 Demand Side Management Programmes in Sweden

The Peak Shave Project (ToppKap)

At the end of the eighties Sydkraft needed to increase generation capacity by 100 MW to meet the demand of the coldest winter days.

A series of projects were run in co-operation with Sydkraft, Swedish Energy Development and Linköping University to determine whether load management could replace the required investment in a gas turbine at lower cost. Control designs were tested and new types of contracts were marketed. Customer categories in the project were single family houses, as well as industries. Technical hardware at customers as well as communication between customer and electricity supplier were installed and tested. Load management was divided into two parts: direct load management and indirect load management. For direct load management the following prerequisites were set:

- The participating loads are directly controlled from the control centre of Sydkraft

- Problems related to returning loads should be possible to treat

- Communication solutions should be in place

For indirect load management the following prerequisites were set:

- Economic information should be communicated to customers

- Customers should act to decrease loads at peak times

One of the subprojects, ”Mintop”, which was started in 1987, concluded that a peak load reduction of greater than 200 MW was possible at a cost well below that of a gas turbine, including marketing costs and compensation to customers. This was based on a number of tests at single family houses and a few industries. To reach a potential of 100 MW the following possibilities should be realised:

Electric heating in single family houses	50 MW
Tap water heating in single family houses	5-10 MW

Industry	20 MW
Large heat pumps	20-25 MW

It was considered possible to make investment in communication and control equipment in 10–15,000 single family houses within a period of two years.

Technical designs for customers and for communication between customers and Sydkraft were tested in the project. The technical design for single family houses used a newly developed system which improved the indoor climate. This equipment was also designed to treat the problems with returning power demand. The results showed that it was possible to decrease the load by at least 4 kW per house on average.

The industrial customers invested in a computerised system to keep track of a number of loads, their status and the total power demand of the company. Communication between Sydkraft and customers was based on radio technology.

After this, the real marketing effort started in a full scale pilot project, ”ToppKap”. This project was completed and showed that load management was cheaper than investment in a gas turbine.

The following table shows the number of participating customers and the total demand reduction obtained.

Category	**Number of customers**	**Load reduction [MW]**
Industry	25	8,1
Large heat pumps	2	2,7
Misc. sector	20	0,4
Single family houses	1400	5,6
Total	1447	16,8

<u>The Industry bid project (source: Industribud okt 02)</u>

This project was initiated in the year 2000 aiming at making industry decrease their energy use in peak load situations. The project was a co-operation between the Swedish System Operator and the Swedish Energy Agency. The customer category aimed at was industry not directly exposed to Nordpool spot prices. The customer offers a power demand reduction (at a certain price) to the balance providing company which in turn puts this offer on the spot market. To realise this, new types of contracts between customers and the balance providers were required. Thus, one of the results from this project was three new types of contractual agreements:

- for customers with a fixed energy price,
- for customers who are partly exposed to the spot prices but pay a fixed charge added to the market price to the balance providing company

(for the imbalances created),
- customers who pay a part of the imbalance costs (so called synthetic balance providing companies).

The idea behind the contracts for the two first categories is to make it possible for them to act as synthetic balance providers through the following actions:

- Before noon (day in advance) tell their terms to the balance provider (prices, volumes hours)
- The balance provider takes this into account when bidding on the spot market
- The contract takes care of profit sharing between parties. Savings take place because the balance provider does not need to pay for expensive electricity on the spot market. The cost relates to decreased production at the customers or that extra electricity generation must be started.
- The contract also takes care of what happens if the industry does not deliver the promised power demand reduction.

The Industry bid project was a marketing project where about 60 industries and some health administrations (emergency power at hospitals) were contacted and interviewed regarding their possibilities to reduce demand. At the visits it was concluded that there were technical and economic possibilities to reduce power demand during one or a few hours.

Reduction possibilities varied from 1 to 100 MW but were normally in the range of 5-50 MW.

The potential demand reduction possibilities in the visited companies totalled 1300 MW, corresponding to about one third of the total power demand of these companies. A number of companies were contacted during the project but were not visited. The possibilities at these companies were estimated to be about 300 MW. This means that the total potential was about 1600 MW.

	Number	[TWh/year] (Total consumption)	[MW] (Peak demand)	Estimated potential for power demand reductions [MW]
Visited industries	27	25	3,500	1,300-1400
Contacted industries	20	7	1,100	200-300
Total				1,500-1700

Summary of the possibilities for power demand reductions at industries (Industry bid project)

Power demand reduction payments for industrial customers vary from €50/MWh up to and beyond €10 00/MWh. In the project it was estimated that the reduction will be around 100 MW with payment of €200/MWh and over 700 MW with payment of €10 00/MWh.

Agreements within the Industry bid concept are based on a relatively high payment for reducing demand at peak load times but nothing if the peak load does not occur. This means that there is a high degree of uncertainty regarding income from the agreement. It was considered by many of the participating companies that peak loads do not occur frequently enough and that the peak prices are not high enough to make the concept profitable. This is a very interesting and important point and seems to be counter to the idea that customers don't want too many interruptions!

A conclusion from the project is that continuous marketing efforts are needed to reach the full potential and that peak prices and peak loads need to occur more frequently than today.

Purchasing of power by System Operator

At the end of 2001 the Swedish System Operator received an assignment from the government to purchase demand reduction amounting to 400-500 MW for the winter 2002/2003. A first attempt was made for the early months of 2002 when the lower limit was set at 20 MW for every participating customer. The customer interest in power demand reductions increased (compared to the Industry bid project) due to the fact that they were promised a fixed economic compensation added to the variable income if "demand turndown" was activated.

For the winter of 2005/2006 there are three classes of notice time, 15 minutes, 3 hours or 8 hours. The contracts between System Operator and Customers/Power producers have both a fixed cost and variable cost component. Over the winter period 16 Nov-15 Mar (Year), the maximum number of times the System Operator could call on providers was 15 times in the case of Power producers and 5 times in the case of demand reduction levels.

The purchasing process has just started for the winter 2005/2006 period. The aim is to obtain 900-1100MW of long term contracts with Power producers and up to 2000MW will be divided equally between Power producers and demand side bids.

ESSELCON load management projects

Demonstration projects are being carried out involving customers that are considered to have conditions to reduce electricity use when high prices occur. The projects are:

- **Project 1:** Direct control of electricity use for direct electric heating of detached houses

- **Project 2:** The price of electricity is variable and during a few hours the price is extremely high. Customers choose whether to reduce the use of electricity themselves. Only detached houses willing to lower the indoor temperature during some hours or detached houses with the possibility to change to another energy source, for space heating, are included in the project.

Results from Project 1

In some areas in Sweden equipment to change electrical demand has been installed. This equipment is called Abelco, and is not primarily installed for load management. However, the equipment may be used for this purpose and comprises load management possibilities of up to 40 MW. In this project 50 customers of Jönköping Energi have been involved with a compensation of €30 each for load management for a maximum of 40 hours per year. On four occasions, with a duration of 2 hours, electricity to the space heating was reduced by 66%. The results show that each detached house on average reduced the power demand by 4-5 kW. The reduction in power demand when reducing electricity to the domestic hot water heaters, in the same way as for the electrical space heating equipment, was estimated to be approximately 1 kW per detached house. This type of direct control is not recommended in the way this test was performed because a peak in power demand occurred in the hour after load management.

Results from Project 2

Over winter period customers of one utility company in the south of Sweden, Lund, were involved in a direct electric heating control project. The following winter, customers from another utility in the middle of Sweden, Vallentuna, were also connected to the project. In the first phase project, 45 customers with direct electrical space heating equipment were involved. Fifteen of the customers had no alternative to electrical space heating while the others either had oil or wood fuel as alternatives. During the second winter a total of 53 customers were involved in the trials in Lund, of which some were the same as the first winter, and another 40 customers in Vallentuna. The customers not having an alternative to electricity heating amounted to 19 in Vallentuna.

The customers were informed by text messaging or E-mail the day before a high electricity price was to occur. The prices charged were 0.3, 0.5 and 1.0 €/kWh, mainly €0.5/kWh, to estimate the price sensitivity. Customers decided how to reduce the load themselves, but were informed by the project leader on ways to cut the power demand.

On 15 occasions, with a total duration of 39 hours, the power demand was reduced by 50% on average when the electricity price was high (between 8 and 10am) in the first winter. However, customers seemed to increase activity with time. This was especially noticeable for customers not having an alternative to electric heating and thus who had to reduce indoor temperature. This may be explained by the fact that customers may not have felt any deterioration in indoor comfort and gradually reduce electricity use further as the trial progresses.

Three different price levels were used during these hours and the results show that the level of prices did not influence the extent of reducing electricity use. However, the project leader does not recommend drawing the conclusion that price level does not influence the degree of reducing electricity use as it is probably the price differential and the total saving that are of interest.

It was evident that no peak in power demand occurred during the hour after the load shedding. The load shedding seemed to hold on for some time after the high price window. This might be explained by the fact that customers do not turn on the electrical space heating equipment and the domestic hot water heaters directly in the hours following the load management actions.

During Project 2 a questionnaire was used to evaluate customer opinions on the project. It indicated that most customers were willing to continue with the project. Those who were not interested in a continuation had bad experiences during the project, such as cold indoor climate and running out of hot water. As a continuation to the project, in-depth interviews are presently (May 2005) being carried out.

As the project has been carried out during two winter periods it is interesting to notice the endurance of the customers. All together 30 load management periods have been accomplished and it is seen that customers are ambitious. The changes in behaviour pattern are also worth nothing, i.e. it takes some time before customers realize the potential of load management and the connected profits.

In the Lund project a division between three different customer loads was introduced: space heating equipment, domestic hot water heating and electricity use in household appliances. Meters for measurements were installed for these three customer loads in 10 detached houses. Customers have been voluntarily enrolled in the project and do not receive any rebate on the electricity bill.

In this project, different types of analyses have been carried out, behavioural, technical and environmental. In one study, tests have been carried out of models based on neural networks that can separate the three customer loads mentioned above. However, the study illustrated problems to find patterns for the two latter loads (Hermansson, 2004). In a further study, a test to implement a new network pricing fee, based on a power charge, was carried out. The tariff was based on the average of the three largest power demand peaks for each month and an extra fee for the size of the customer house fuse. When compared with present tariffs for the electricity grid the test showed that customers with the largest size of fuse receive a reduction in their grid cost, while the customers with the smallest size of fuse faced increased grid cost (von Knorring, 2004).

Using the same 10 households as before, load management was applied in experiments with direct load control to:

- test the technical possibilities of direct load control.
- estimate what load savings could be achieved,
- estimate how indoor climate and comfort conditions for customers are affected
- estimate the availability of hot water.

Also, environmental aspects of load management were partly studied (Abaravicius, 2004).

The results from the direct load control showed that the heating savings in principle depend on house area. The potential demand reduction from heating varies from 1.1 to 3.8 kW per household. However, recovery load occurs when the system is reheating the house after the control period, which can result in another, even higher, peak after control. “Soft heating systems” that keep the load below a certain level can be used to overcome this problem. However, for the household it could mean a longer loss of indoor comfort. The temperature drop in this study was up to 2C (Abaravicius, 2004).

It was not possible to determine the size of the savings for the hot water system as water use measurements were not performed. However, domestic hot water systems have a large potential for load savings. Most of the systems have tanks with 300 litres of volume, therefore interruptions for 1 to 4 hours or even longer would not have serious negative consequences (Abaravicius, 2004).

An investigation of how the comfort of space heating and availability of hot water change during direct load management was also undertaken within the same 10 detached houses during a three-week period. Space heating and domestic hot water heaters were shut down for 1-4 hours, without the knowledge of customers. An analysis of the reaction to load management by the households after these trials was carried out. Two main criteria were investigated, the response to the reduction of indoor temperature and the hot water supply. Through interviews it was shown that customers were aware of some of the load management occasions but not others. During longer load management times on space heating, customers noticed the difference in temperature. Customers did not notice load management of hot water heaters. Almost all customers are willing to accept load management in the same form as in the study. However, half of the customers would like a special device that notifies them when there is load management. The majority of customers think it is a matter of course that they are compensated for allowing load management in their homes (Sernhed, 2004).

According to the results of the study, the conclusion is made that both direct and indirect load management, from a household perspective, are possible to implement. However, further studies regarding the legal consequences of this type of load management are needed. The responsibility for the installed devices needs to be determined because devices may not work properly or disturb other machines at home. Moreover, the sharing of the financial savings needs to be established and studied in future analysis. The economic incentive for both utility and customers need to be investigated and how to validate the power demand change. This needs to be considered especially when indirect load management are used, but the interviews show that it is also desirable during direct load management. Implementation of load management and how to avoid after hours peaks are also vital to consider further. The type of demand “turndown”, on or off or thermostat change needs to be further investigated.

Summary of Sweden Field Trials

Demand response activities are high on the agenda again after reduced interest during the nineties. A list of conclusions can be drawn:-

- Customers are willing to decrease their power demand

- Customers may sometimes participate without getting paid, just for the interest of society

- Customers learn with time to increase their ability to decrease demand

- A fixed payment is a good driving force, but it need not be large

- Specialised technical equipment at customers may not be needed (for smaller customers)

- Industrial customers need repeated information to get over the threshold of interest in demand side participation

- Communicating price information and demand switching for customers needs to be simple. Telephone is used today for large customers. For the mass market radio was used in the 80’s, may be Internet will play a part in the future.

- Contracts must be individually adapted for industry, but may still be quite simple.

4.3 Field tests of direct load control response models in Finland

Accurate response models of load control are very important for the success of load control optimisation, for the validation of the load change, as well as for estimation of the availability of DSB potential. In order to verify and develop these models, so as to predict demand change when loads are interrupted, field tests with direct load control systems were carried out between 16 December 1996 and 24 January 1997 in northern areas of Finland.

In these field tests there were 8283 load control terminals controlling various space-heating loads such as in small houses and ski resort holiday homes. The power at the supplying substations was measured. However, power measurements at some substations were not used in the research because of too coarse time resolution or data communication failures. Thus the tests included 463 holiday home terminals (most of which controlled several holiday homes each) and about 5666 small houses. Based on the measured after peaks, it can be estimated that the total maximum power of the controlled loads included in the test was about 20 MW. The actual controllable power is much smaller except for very cold weather.

An example of measurement data during one test day is shown in Fig 8. Four load groups were controlled to off-state for half an hour, each group at a different time. Controls started at 10:15, 11:30, 13:15 and 14:20. (After 15:00 a data communication failure and half an hour later a system failure show their effects on the recordings. The ripple in the data is mainly caused by the rather large measurement pulse size.) The weather conditions were not good for load control tests, because all the cold periods were too short. However, a newer physically based model structure worked quite well. The load control model has several parameters, but this is compensated for by its ability to use prior information on the thermal properties of the houses. For example authority requirements on buildings, for the particular temperature zone, give very good prior estimates for the insulation, ventilation and heating parameters of the model. The effect of outside temperature is also built in the model structure.

In Fig 9 an example of the response of the model is shown. The measured load represents two ski resort areas and the measurement of a reference day has been subtracted in order to reduce the effect of other load variations from the results. This case is chosen so that the raw measurement data is included in Fig 9. Four different load groups were controlled, one at a time. The outside temperature was around -19^{o}C. The parameters for the prediction model were identified from load control tests of normal houses in another nearby utility. However, advance information on the total controllable power and heat storage capacity was used to scale the respective parameters of the model. The power was known. It turned out that slow dynamics are hidden behind other load variations and thus advance information of large heat storage capacities is useful in the model.

Fig 9 shows the measured response against which the models were compared. The measurement curve shown is the difference between the test day and the average of several reference days. During the test the temperature was around -7^{o}C. Good correlation between measured and predicted responses were obtained.

Advanced load control terminals may limit the after-peak for example by reducing temperature set-point temporarily. It is easy and straight-forward to include such features in the load response model.

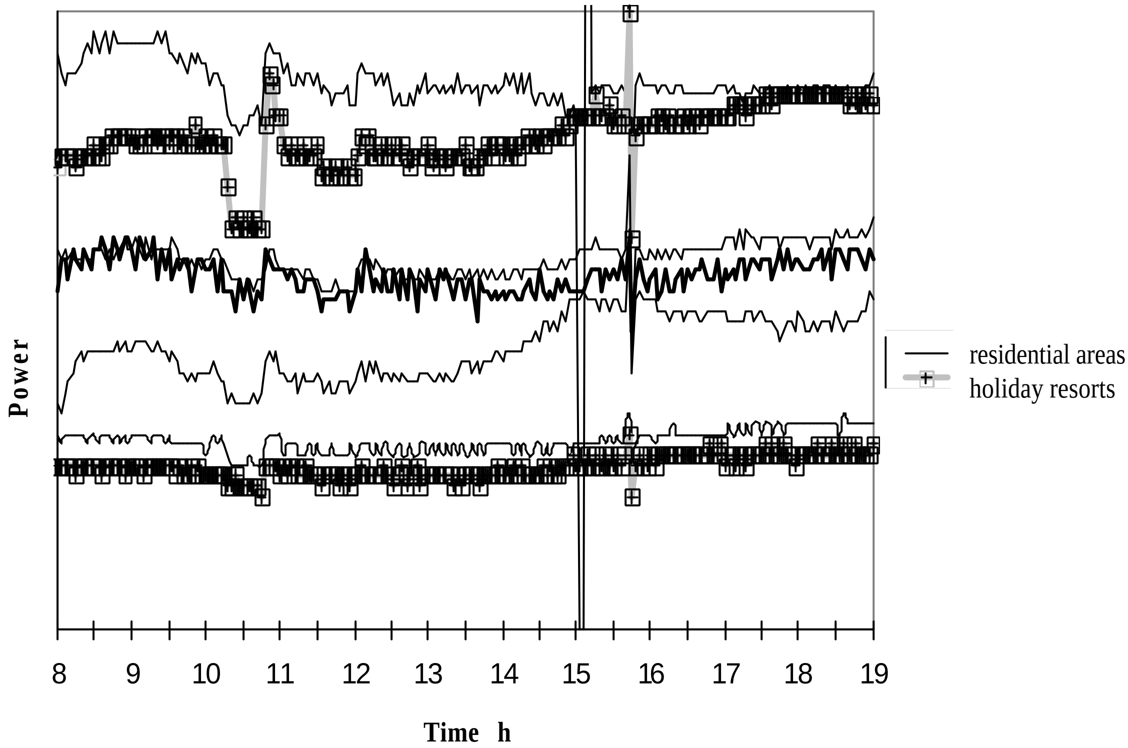


Fig 9 An example of primary substation load measurements, 16 December 1996.
Four load groups were controlled one at a time, controls start at 10:15, 11:30, 13:15 and 14:20.

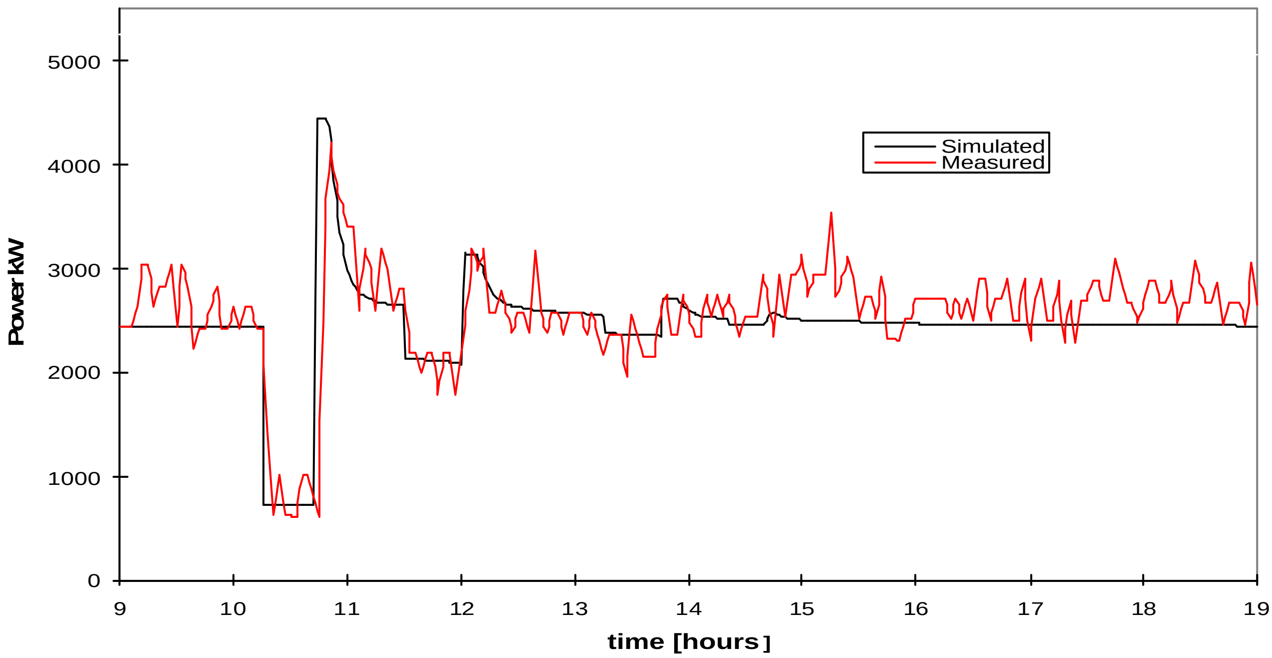


Fig 10 An example of the prediction performance of the model. 16 December 1996.
The measurement is the power of the holiday areas in Fig 10 with a reference day power subtracted. The simulation model parameters are based on another day and other substation, but adjusted using prior information on group size and heat storage capacity.

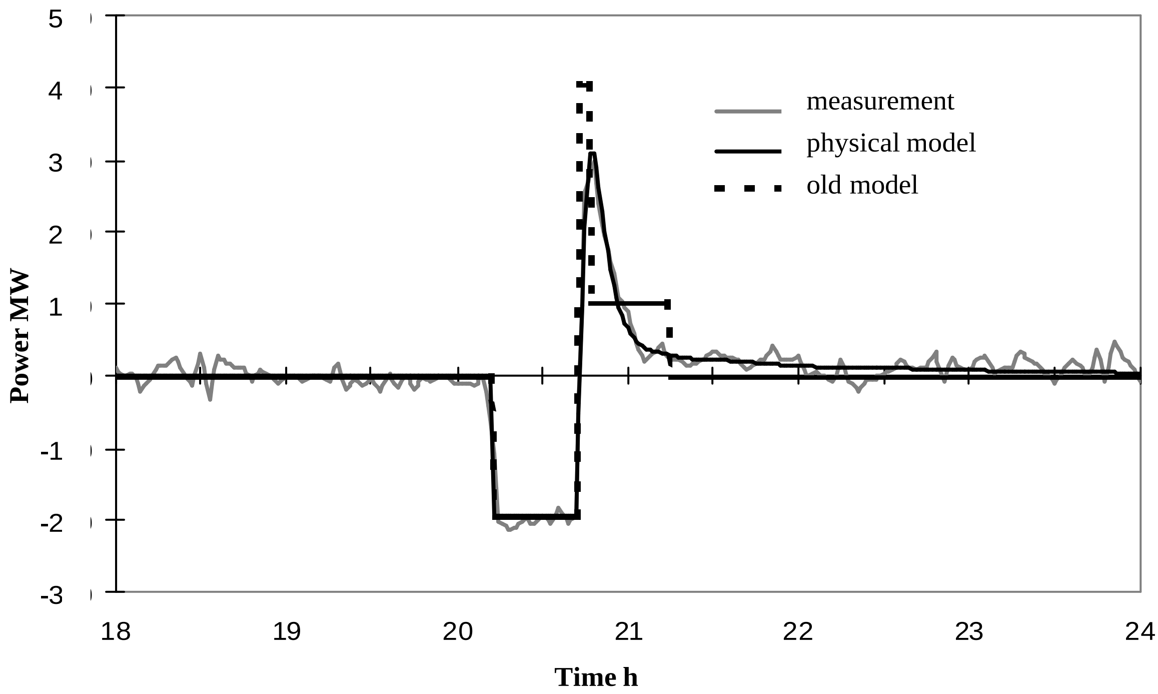


Fig 11 Comparison of the physical load response and of the old models. Both models are fitted to the measured response that is also shown. Outside temperature is -7 ^{o}C

Also a time series analysis was applied to the measured data. It turned out to be very poor in estimating the long-term dynamics of the loads. In general no good alternative to advance information was found for modelling the slow heat dynamics of the loads from substation measurements. However, fast dynamics of the load control responses can be identified using the physically phased model structure from very few tests. This is very important, because direct load control is very seldom applied.

The following differential equations (1) show the structure of the physical load response model applied in Figs 10 and 11.

$$
\begin{aligned}
C_1 \frac{dx_1}{dt} &= -k_{12}(x_1 - x_2) + P \\
C_2 \frac{dx_2}{dt} &= k_{12}(x_1 - x_2) \\
&\quad + k_{23}(x_3 - x_2) \\
&\quad + k_{24}(x_4 - x_2) \\
&\quad + k_{2o}(T_{out} - x_2) \\
C_3 \frac{dx_3}{dt} &= k_{23}(x_2 - x_3) \\
&\quad + k_{3o}(T_{out} - x_3) \\
C_4 \frac{dx_4}{dt} &= k_{24}(x_2 - x_4)
\end{aligned}
\tag{1}
$$

where

t	time
$P(t)$	heating power
$x_1(t)$	temperature of the heating element
$x_2(t)$	temperature inside the building
$x_3(t)$	temperature of outer walls
$x_4(t)$	temperature of heat storage not directly connected to the heating element
C_1, C_2, C_3, C_4	heat capacities respective to the above temperatures
k_{12}, k_{23}, k_{24}, k_{2o}, k_{3o}	heat transfer coefficients
$T_{out}(t)$	outdoor temperature,

In addition the model includes a PI-controller that regulates the indoor temperature to set point value T_{set} by controlling the heating power. During load control periods and power interruptions the heating power is zero in the model.

$$
\begin{aligned}
P(t) &= f_{PI}(T_{set} - x_2(t))\, u(t) \\
0 \le P(t) &\le P_{\max}
\end{aligned}
\tag{2}
$$

where

u(t) = 0 , during direct load control periods and power interruptions
u(t) = 1, otherwise.

The structure of the model (1)-(2) is illustrated in Fig 12.

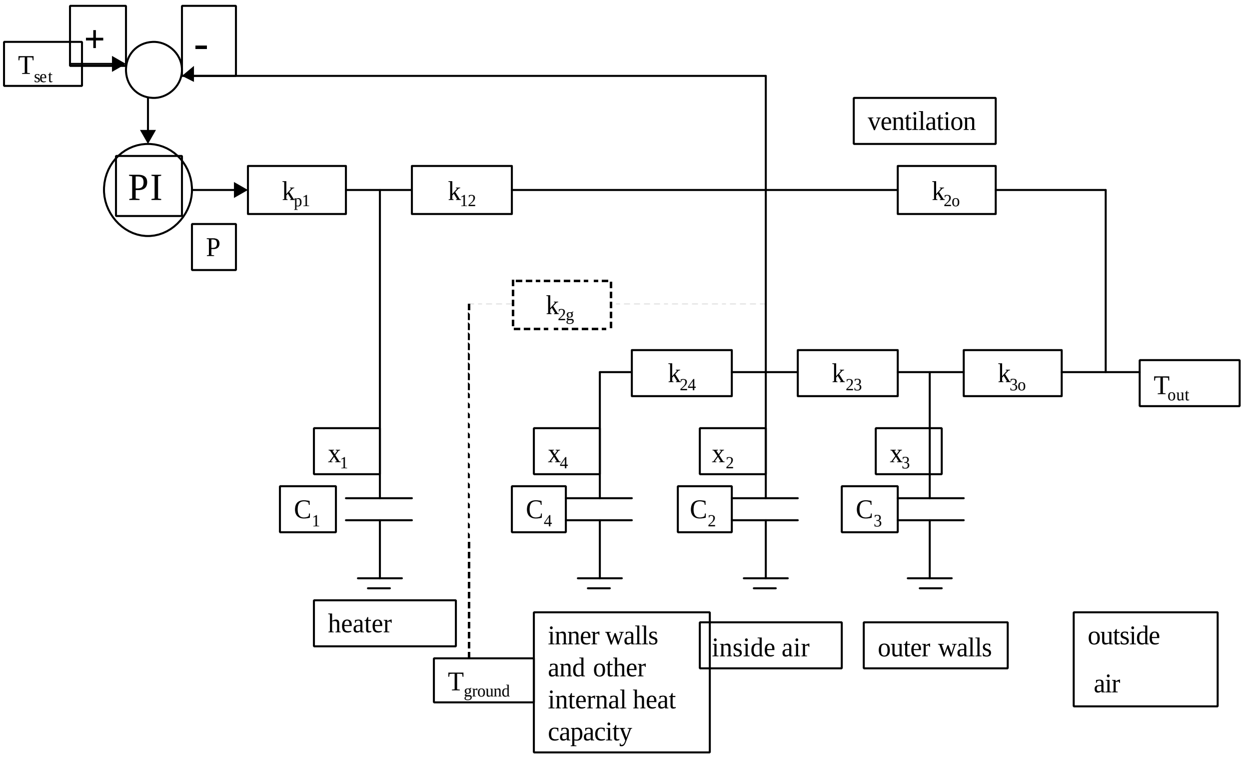


Fig 12 The structure of the direct load control response model

For each load control group the model parameters were fitted to power and outdoor temperature measurements from primary substations. Advance information of the insulation and heat storage capacity of the buildings was used to constraint the search for the best fit. These reasonable constraints also helped to avoid local optima of the parameter fit.

The experience with these tests can be summarised as follows.

1) For response modelling and verification, the applied 3 minute measurement time interval was adequate but cannot be longer. The accuracy of the measurements suffered from too coarse measurement pulse sizes, but changing them was not allowed, because the same pulses were fed to several systems of different energy market players.

2) Modelling methods that are only based on measurement data require more response data than is available in most practical situations. Direct load control is applied very seldom at the present time and the environmental and load conditions change. It is much better to use physical models that combine advance information of model structure and parameters with model data. In this way direct load control responses can be predicted with useful accuracy. It may be assumed that the physical model based approach works even better, when the power of individual load control points is measured instead of primary substations.

3) Electric space heating loads have significant distributed control capacity that could be very useful for DSB.

4.4 Demand Side Management Programmes in the UK

Storage Space Heating and Water Heating

For a number of years radio tele-switching has been used in the UK to stagger the start times for charging domestic electric storage heaters and hot water cylinders. A recent initiative from the UK System Operator has led to tele-switching of the storage demand to provide System Stability services. This is an interesting application since, unlike the other System Stability products the System Operator buys, there is no metered proof of “available” load – simply estimates made from the number of systems in operation, time of day and weather conditions and series of tests.

It is likely, however, that in most cases Planned Balancing (including System Operator instigated peak demand reductions) will be the major use of domestic DSB products.

Most of the successful applications of DSB to date have been used to deal with abnormal or unusual situations. System Stability issues are by their nature abnormal, in that they are caused by some unpredicted situation – such as a loss of a major generator or a sudden increase in demand. The successful Planned Balancing examples have tended to be in generation limited networks, where peak demands are reduced for just a few hours per year. A similar scenario exists in network constrained regions where the transmission system is stretched to its full capacity for only a few hours per year.

The more general case is where demand-side participants reschedule their electricity use to follow price signals on a daily, or even hourly, basis. In some networks, particularly where there is a high component of reliable and controllable hydro electricity, this is unlikely ever to become important, as witnessed by the very flat spot prices for most of the year in countries such as Sweden and Norway. However, in other markets, within the day variations in electricity prices are common, and customers (the providers of DSB) having the flexibility to respond to price signals, could become very important to Suppliers wishing to minimise their overall costs. The greater use of non-firm and intermittent generation (wind, solar) could make this demand-side flexibility ever more important in the future.

Demand “Turndown” Trials

Demand Turndown was a pilot scheme for providing contingency reserve via the reduction of load by large customers or Aggregators of smaller demands or generation. The pilot scheme took place over the period 5 April 2004 and 30 July 2004 in order to prove the ability of the demand side to deliver a reliable, secure, quantifiable and economic service.

Commercial contracts were put in place for single dispatch with a minimum turndown of 100MW sustained for at least 2 hours during a predefined service window. The minimum aggregated load of 100 MW represented the minimum level of "turndown" that the System Operator will accept in order to deliver an appreciable gain in operating margin.

During the summer months, the service windows were timed to coincide with the summer morning peak hours of 09:30 hours to 13:30 hours, as indicated in Fig 13.

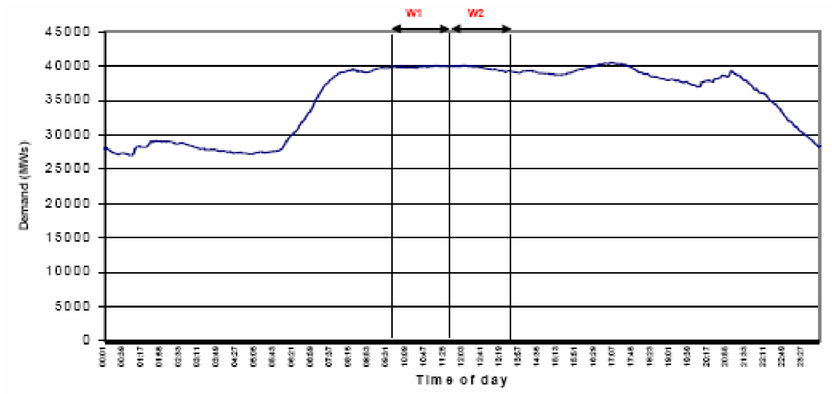


Fig 13 Typical summer demand profile

The Aggregator was required to identify the demand sites taking part in the trial primarily to ensure that sites were not providing two demand side services simultaneously, but also to assist the System Operator analyse the effect of location on demand "turndown". Meter data was provided to the System Operator on an aggregated, minute by minute (preferred) basis or half-hourly basis.

The demand "turndown" mechanism involved two phone instructions from the System Operator to the Aggregator; a standby instruction and a call-off instruction.

The standby instruction indicated that the demand sites must enter a standby mode and be prepared to receive an instruction to "turndown" their demand. The call-off instruction is the term used to deliver the demand "turndown", and can be issued at any time from the standby instruction up to the start of the call-off period. The call-off period represents the minimum amount of time that the demand side provider requires to deliver the contracted MWs. The providers were free to specify the notice required to enter the standby mode and the notice required to deliver the demand "turndown", a level of flexibility that is not available with other demand side products. The providers were required to inform the System Operator, via e-mail, of the contracted sites, the window and the contracted MWs available for demand "turndown" one week ahead of time. However, providers were permitted to re-declare their availability up to one day ahead of time (before 17:00), but only if there were problems with the technical capability of the site. Fig 14 provides an overview of the process involved in utilising the demand "turndown" bids.

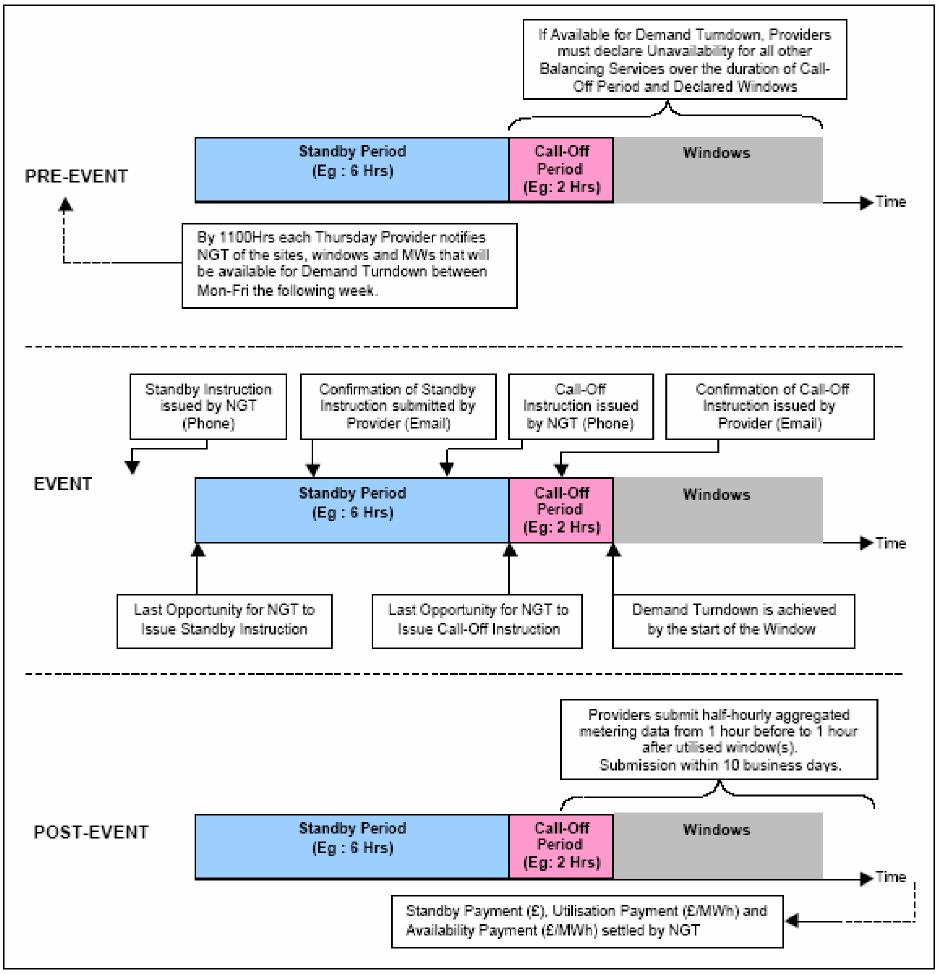


Fig 14 Utilising Events in Demand Turndown Call-Off

Retrospective daily demand profiles based on minute by minute metered readings or half-hourly aggregated data was provided for validation that demand “turndown” has been delivered as contracted, and also to permit the System Operator to assess the accuracy of the forecast daily load profiles against actual consumption.

Three payments were made to participants in the trial;

- An availability payment
- A standby payment
- A utilisation payment

The availability payment was made to reflect the costs incurred by customers in participating in the trial, mainly as a result of the requirement to provide forecasts of availability and post-event consumption data. The payment was made on a €/MWh basis, contingent that the week-ahead declared availability and the day-ahead re-declared availability was within 10% of the metered MWs. The Standby payment, only paid when a customer was called to standby, was a fixed fee made on a Euro per day basis. The utilisation payment was made when the customer was given the instruction to "turndown" the demand and was paid on the delivered MWs up to the level of declared "availability". The delivered MW were the difference between the average demand in the two half-hours immediately prior to the instruction to "turndown" and the demand during the service window. Fig 15 shows an example demand profile for a customer requiring two hours notice in order to deliver the full demand reduction.

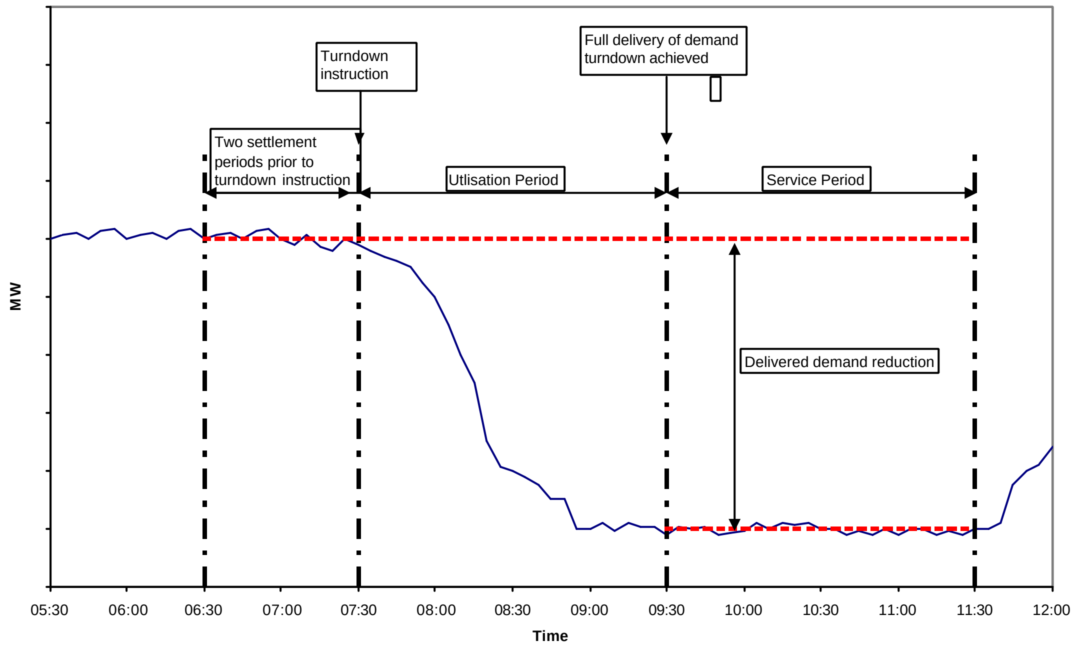


Fig 15 Metering demand "turndown"

It is interesting to note that the customer has flexibility in setting the standby notice and call-off notice required. Thus, a customer may stipulate that they require 12 hours notice to standby for a demand "turndown" instruction, but only 2 hours notice to deliver it. This customer beginning to reduce demand early in anticipation of a demand "turndown" instruction would be penalised and not receive payment for the true level of demand turndown delivered.

<u>Domestic Off-Peak Demand "Turndown" (Demand available for "turndown" only during "off-peak" periods)</u>

Of the 2.5 million multi-tariff residential customers with off peak, storage space heating and the capability for dynamic switching (via Radio Teleswitch), only 5-10% of these have sufficiently flexible contracts to permit active load management during the nominal off-peak time period. However, the System Operator in England and Wales, has recently conducted a number of trials to investigate the potential of active load management using broadcast radio. In total, three different trials were conducted during the winter of 2002/2003. Two of the trials involved short term interruptions to the off peak charging period to assist the System Operator with balancing the network in real time. The other trial involved the rescheduling the off-peak demand.

Demand Profiling

This trial involved re-scheduling the off-peak loads to move demand from peaks periods into the troughs, as indicated in Fig 16.

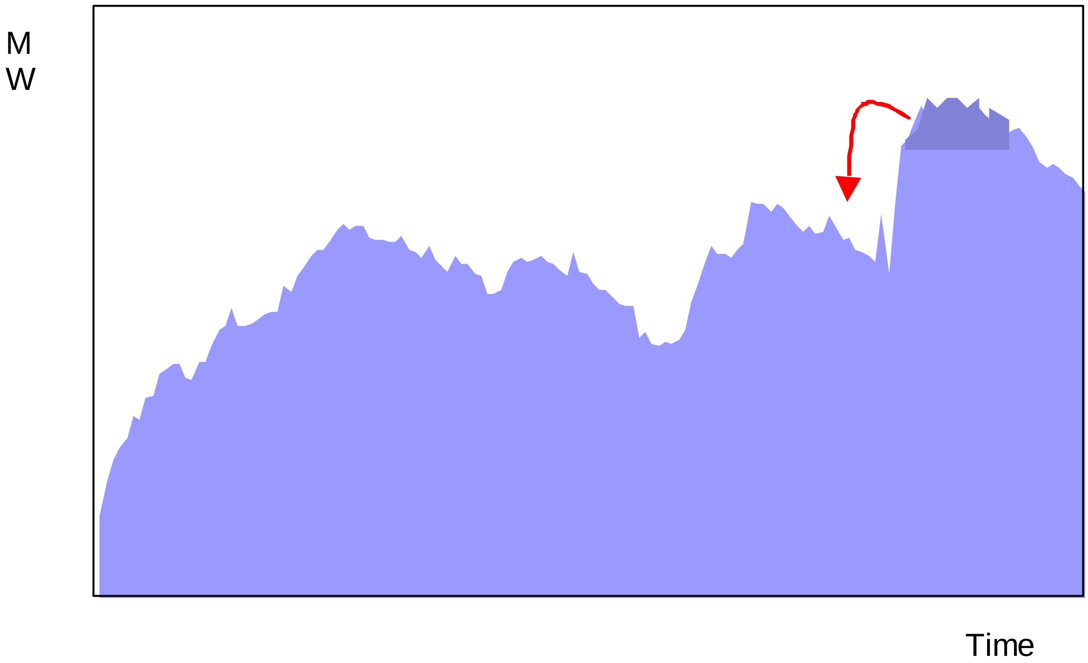


Fig 16 Schematic of the demand profiling trial

The results of the trial are largely confidential, but the System Operator has indicated an intention to continue the trial over the winter of 2003/2004. The total contracted demand for this service was 600 MW, which represented around 2% of the peak demand during the off-peak period. However, NGT noted that the actual volume delivered was volatile, i.e. it was not possible to be certain the level of demand that would be shifted at any one time. Although, the amount of demand that was shifted during the trial could not be directly metered, comparison of the actual system demand with the system demand determined using profiles did give a good indication of the amount of demand shifted in this way.

Radio Broadcast Trial (Teleswitch)

The aim of this trial was to see if radio-teleswitching could be used as a means of utilising domestic customer demand “turndown” as a means of providing fast reserve, i.e. for immediate demand dispatch. The trial was considered a great success with between 50MW and 300MW of demand reduction delivered, as shown in Fig 17.

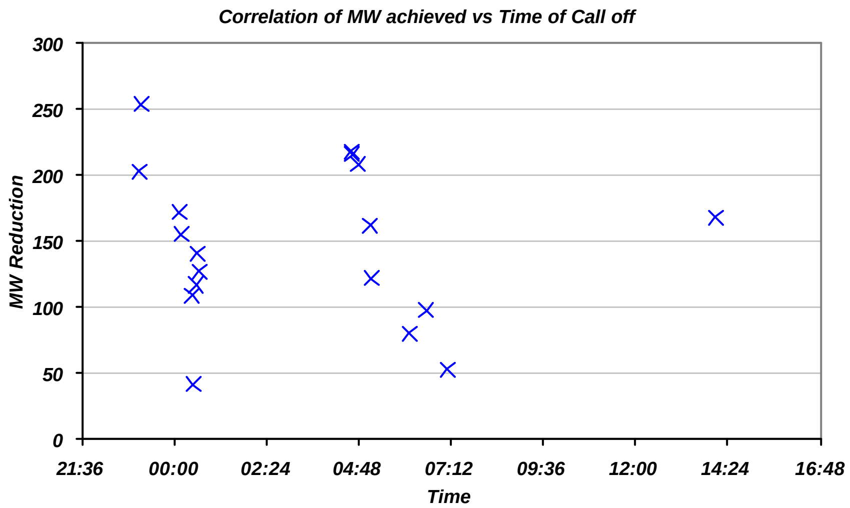


Fig 17 Results of NGC Radio Teleswitch Trial

The trial highlighted limitations of the current Radio Teleswitch equipment due to its age, but that these could never-the-less be 'engineered around'. There was some concern over the suitability of the Radio-Teleswitch for providing near instantaneous demand reduction. For example, in some regions it could take up to 10 minutes for the Radio Teleswitch broadcast instruction to reach the meter. However, the System Operator noted that delivery was near instantaneous during the trial. As with the demand profile trial, the System Operator noted that the actual volume delivered was volatile, i.e. it was not possible to be certain of the amount of demand that would be reduced at any one time. Although, the amount of demand that was shifted during the trial could not be directly metered, comparison of the actual system demand with the system demand determined using the settlement profiles did give a good indication of the amount of demand shifted in this way.

<u>Cyclo-Control Trial</u>

Cyclo-Control uses Power Line Carrier communication to broadcast messages to customer premises. In this case, the instruction to reduce demand required the System Operator to telephone the supplier in order to implement the broadcast message, which made the product less than ideal for the System Operator who was looking for near instantaneous demand reductions. As with the other trials, the System Operator raised the volatility of the actual volume delivered as a matter of concern. Fig 18 summarises the demand reduction that was delivered during the trial based on the time the "turndown" signals were transmitted.

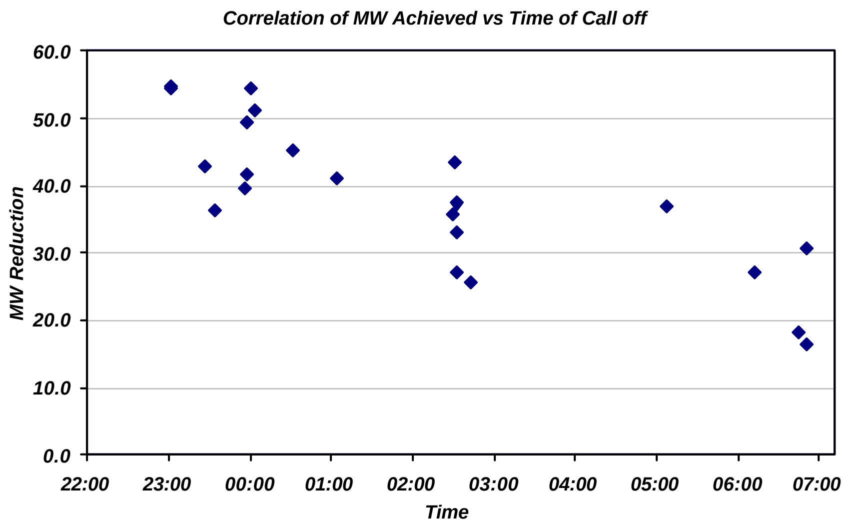


Fig 18 NGC Cyclo-Control Trial Results

Fast Acting Frequency Response

In the UK the System Operator must respond to a sudden loss in frequency within a prescribed time period. Various products have been defined in order to help achieve these requirements. One such product is a *Commercial Frequency Response initiated by Low Frequency Relays*. This product can be provided by either generators (typically generators in a state of readiness – spinning but not on-line) or by the demand side. The particular basic commercial frequency response product that is suitable for the demand side "turndown" has the characteristics of:

- Response delivered in full within 2 seconds
- Minimum demand 3 MW
- Duration of change 30 minutes

In reality, the response of demand to a frequency relay is instantaneous (within micro-seconds), giving a clear advantage of the demand side over generators.

How often the service is called upon to operate depends on the settings of the relays at customer premises, as shown below. The payment for delivering the 'product' may vary to reflect the different settings. More likely is that an Aggregator would have several customers, each being paid the same. Frequency trips would be set at different levels to provide a progressive change in demand as the frequency falls. The setting of the relay would then be varied throughout the year, from site to site, to give each customer a similar number of trips per year as shown in Fig 19.

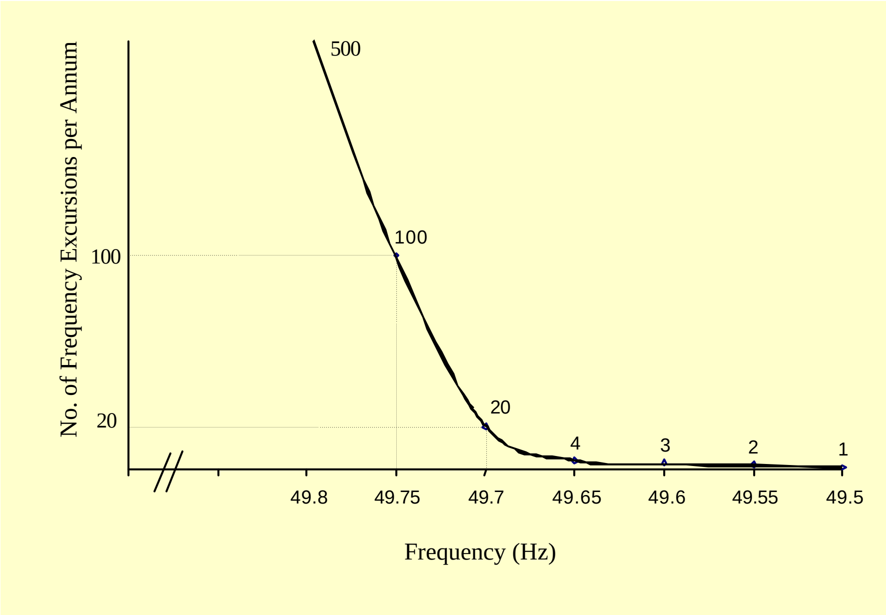


Fig 19 Number of Interruptions in Demand against Relay setting

Frequency trips are automatically reset after 30 minutes.

The System Operator procures Frequency Response services through bi-lateral contracts. These are negotiated on behalf of customers by an Aggregator. The contract stipulates volumes and also a price for availability.

The Aggregator has a portfolio of customers offering the service. These notify the Aggregator of their load schedules for those processes available for frequency control. The Aggregator totals these offers of "availability" and relays them to the System Operator by the week ahead of the "availability" being offered. Offers can be refined a day ahead, for example to cover production problems at the plant.

Great efforts are taken to reassure customers that DSB "availability" will have as little impact on their business as possible. Customers can automatically undeclare their availability at any time, by pushing a button at their plant. Production schedules and combined offers of "availability" are conveyed to the relevant parties by email.

As of March 2003, there were a total of 25 sites providing frequency response, representing a total demand reduction of 440 MW. The service is procured via an Aggregator who collects the loads into a single offered demand. The service is typically provided by cement works, gas manufacturers or steelworks who are able to provide large load reductions at little or no notice. The service is divided into two options, firm and probabilistic.

- Firm Demand: The crushing and milling phases of cement production consume large, predictable and steady electricity loads that can be easily interrupted and restarted, and therefore makes them ideal for providing firm frequency response to the System Operator.

- Probabilistic Demand: Arc furnaces are capable of instantaneous shut down with no adverse affect on plant. However, individual are furnaces have very high, but irregular, patterns of electricity usage, fluctuating from zero demand to over 50MW within a half-hour, as indicated in Fig 20 below. Therefore, as individual plant they are unsuitable for frequency response. However, load of several arc furnaces can be aggregated together to provide probabilistic frequency response. Aggregating arc furnaces in this way provides a level of comfort to the System Operator as to the minimum level of demand reduction that is likely to be delivered for at least 90% of the time. This is a similar situation to demand reductions likely to be delivered by smaller customers so that a similar aggregation process is needed.

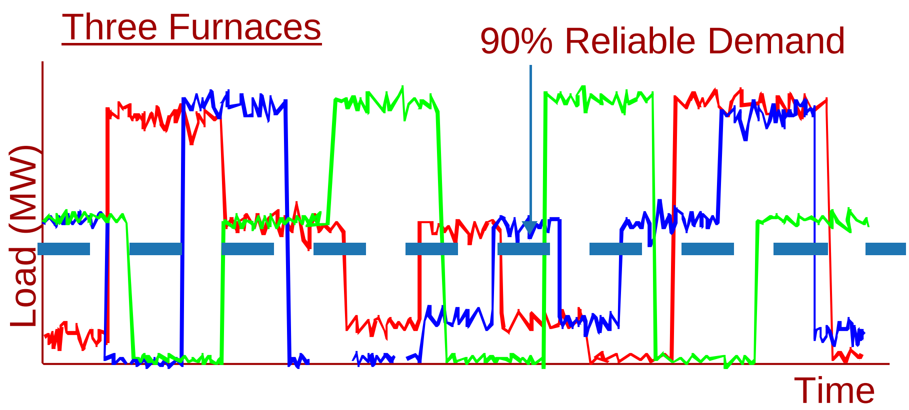
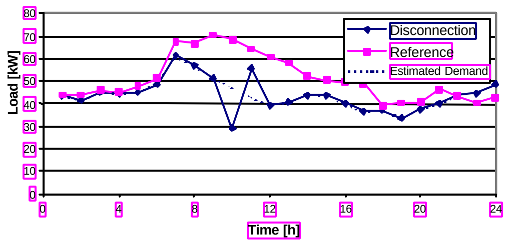
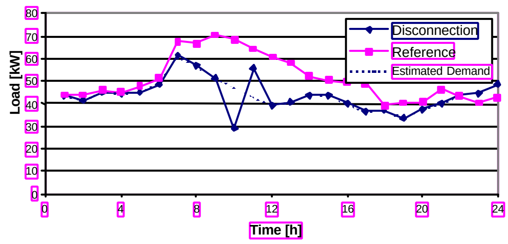


Fig 20 Fast Acting Frequency Response – Probabilistic

4.5 Demand Side Management in Norway

A DSB demonstration has been carried out by interrupting boilers providing direct space heating in schools. Any interruption to the supply will result in a change in the normal operation of the process (i.e. a change in the space heating), the thermal mass of the building maintaining comfort through the period of interruption. The graphs below show the effects of interrupting the boiler supply for one hour from 9-10am, at two different schools.





In both cases the demand increased above the reference case when the supply was returned. This process recovery is important in determining whether or not the demand reduction is worthwhile, or simply creates a new problem later. Nevertheless, this type of interruption, which is cheap to implement, and for limited periods has little or not noticeable effect on the comfort of the occupants and can prove valuable to System Operators or Suppliers trying to balance demand of a full portfolio of customers at the lowest cost.

The provider (the school) will be rewarded with a lower price than the normal supply contract. Furthermore, tests have shown that the electricity used on a day with a supply interruption of an hour or so, is lower than that on a day with no interruption. Thus there should be no problem convincing the provider that savings will be made.

5 Validation and Reward for Smaller Customer DSB

Demand Side Bidding mechanisms use specific payments to customers to motivate them to reduce or increase demand at times suited to System Operator and Supplier needs. These times can be when generation capacity shortages or high prices occur but also when it is economic to use demand changes rather than generation changes as part of scheduling and security assessment. Making changes to demand is valuable to Suppliers in helping balance their supply contracts. These mechanisms can also be applied to the use of standby generation located at customer premises which can be started in response to price or a request associated with a payment and represents "turndown" of customer demand.

However, validating that individual customers demand has "turned down" and is eligible for payment needs to take place.

5.1 Demand Change Validation

In order to reward customers for bidding and "turning down" demand in response to System Operator/Supplier requests, validation that demand has actually been changed is required. Because Aggregators are necessary in order for smaller customers to bid demand, validation of the aggregated demand is needed in order to reward Aggregators. Aggregators can then reward customers for their participation in delivering the demand changes. Existing validation systems for rewarding larger customers rely on individual customer demands being bid and TOU metering (half hour or minute by minute) to compare pre and during "turndown" demand. This mechanism is impracticable for smaller customers because of the erratic nature of smaller customer demand and the cost of TOU metering and verification processes.

Demand Response and Demand Side Bidding, especially for larger customers, have been the subject of a number of analyses and studies in the Danish, Nordic and other markets. Part of this analysis has been within the EU EFFLOCOM project where a DSB process for smaller customers has been established. In this project, single family houses with direct electric heating offer to turn-off part of the heating through a bidding system using Web-pages. In the project, the System Operator aggregates the demand reductions directly using remote metering. This is possible because it is a pilot project with only 25 single family houses participating. Customers have the option to make the demand "not available".

A lower cost mechanism for smaller customer validation for wide scale implementation is to reward them through the tariff and to have automatic and non over ride implementation of demand changes. These changes and the contract between customers and Supplier/Aggregators, would be based on defined parameters. These parameters could include the frequency of automatic demand changes, their duration, the maximum number per year and the interval between them. Some demand changes would include defined notice times before implementation. Others would involve a warning of a possible instantaneous implementation of an automatic demand change during a defined time period. Aggregated smaller customer demand change is statistical because the short term energy usage patterns are variable, particularly thermostatically controlled demands. However, Aggregators would be responsible for delivering contracted demand changes when requested by System Operators/Suppliers. Aggregators and buyers of demand side change services would develop an understanding of what demand changes were likely to be delivered by the implementation of individual switching instructions communicated to customer end uses of energy. These aggregated changes are likely to be at least tens of MW so that it should be possible to "validate" their implementation at grid metering points, at least by using modelling techniques. It may also be possible with experience, to predict demand change which takes place as a result of issuing each specific demand change communication to customer demands at specific times during the day and year. Validation that the specific instructions have been sent out may be sufficient to validate that the predicted demand change actually occurred. However these mechanisms rely on customers not being able to override the switching instructions or, if allowed, choose not to do so.

Demand aggregators would be paid for delivering contracted demand changes following System Operator/Supplier instructions. Payments for participating in DSB are presently based on the size of the 'demand block' that has been switched, the duration of the demand reduction, as well as being "available" for reduction. Payments to smaller customers are likely to be most viable using a flat rate tariff with no override of the switching signal allowed. Consequently a single rate meter could still be used.

It is likely, that customers would prefer an option to not be "available", but with some sort of economic penalty. One way would be a "fine" for bypassing the open switch, which would however increase the complexity of the local control equipment. Again, it may be assumed, that not being "available" is a rare event, in which case it need not affect the amount of "turndown" offered by the Aggregator. It could be included in the form of an agreed uncertainty. However, if a "turndown" instruction is issued on Christmas Eve, then the amount of "non availability" may be high, but may be anticipated through statistics and experience. However, uncertainty reduces the value of the service to System Operators. Aggregators can allow for this risk in bidding demand into markets.

The success of systems for validating “turndown” of “available” demand/ generation are also influenced by how often the actual “turndown” requests are issued by System Operators.

Initial “turndown” commands must be initiated by System Operators and then remotely activated by Aggregators. The system requires local intelligence at customer premises in order to manage the demand of end uses. This can be either centrally placed in the house, with communication to the appliances etc. or it can be located directly in the individual appliances, or even in the sockets.

If “turndown” is required for critical situations which are rare events, then orders will only be issued only a few times per year. For participating customers, there are therefore no incentives to change their consumption pattern or behaviour in anticipation of the possibility of being “turned down”.

In this situation, the validation of “available demand” can be based on customer statistics and/or modelling. This statistical information can be obtained by a combination of:-

- Information on the actual managed installations at individual customers, i.e. electrical heating or not, dishwasher, washing machine, number and types of lamps etc.
- Information on the total metered consumption of individual customers.
- Available statistical information regarding the profile of particular customers based on estimated consumption pattern of various appliances and installations.

The System Operator/Aggregator validates customers from the demand contracted plus the above statistical profile and/or modelling.

This estimated demand change mechanism is similar to that used for aggregated arc furnace validation, described in Chapter 4. Here, a mean demand reduction is assumed to be delivered by switching off a group of arc furnaces each with a short term, unpredictable load profile.

Such a system could be based on contracts taken out each year. Keeping the Aggregator independent of the Supplier allows continuity of contract even when customers change Supplier. However, rewarding customers through the tariff requires liaison and close co-ordination between Supplier and Aggregator.

If demand turndown orders are issued more frequently, i.e. several times every month, then changes in customer habits must be anticipated if override options are allowed. Monitoring of individual demand changes may then be necessary, making the DSB process more complicated.

One-way communication between Aggregator and customer is sufficient in the first case, it may prove necessary to have a two way communication in the latter: one to give actual information on "availability" of demand, from the customer to the System Operator/Aggregator, and the other in the opposite direction to carry out demand "turndown".

Many different types of "in house" communication possibility are available, PLC, Radio etc. The communication channel to the individual customer could be independent or in combination with remote metering.

Two way communication for remote metering is being rolled out for smaller customers in some countries and this could help with the validation process.

A summary of potential mechanisms for validating and delivering DSB for smaller customers is presented in the following table.

Mechanisms for Smaller Customers DSB

Making the bid	The Aggregator predicts usage patterns and decides when it will be most advantageous to interrupt supply, taking into account spot prices and the expected demand levels of his customers. The actual mechanism for making the bid is his normal spot market purchase mechanism (either a reduced bid or a negative bid).
Proving load is available	In the general case of Supplier buying "turndown", there is no need to prove load is available - it is the contract position of the Supplier that is important, and hence how much load he buys or sells on the spot market. Where the System Operator is the buyer of "turndown", the total "available" consumption of a geographic group of houses will be estimated. Assumptions will then be made as to how much of this demand can be interrupted to reduce the system peak.
Receiving notification to modify consumption	The householder may not be aware of the DSB process (or find it unobtrusive), and so interruptions need to be implemented automatically. A number of systems have been investigated: • Ripple control (e.g. Finland) • Radio tele-switch (e.g. UK) • Internet (e.g. Norway) • TV (e.g. Norway)

Controlling process to modify consumption	In Finland, systems simply disconnect part of the heating supply, and there is no partial control of the heating. Norway and Denmark have investigated changing space temperatures – reducing room set-points for a few hours – rather than giving a hard disconnect. In the UK advanced storage heating control has been used to optimise charging periods against time of day electricity prices. In Sweden, TOU pricing has been used in trials with manual actions by smaller customers required in order to change demand.
Process recovery	In the Nordic examples in particular there is likely to be a slight increase in use after the interruption period.
Communicating result of DSB	The householder will receive any benefits of participation via the normal householder billing process. However, behind this may lie some complicated calculations.

6 Rewards and Costs for Smaller Customer DSB

6.1 DSB Service Payments

Payments for DSB, "availability" and "turndown" vary significantly across participating countries. Payments range from zero to €7000 per MWh in one case to a fixed payment of typically €100 per year in another. Another payment system uses up to €6 per kWh reward for peak reduction.

In a project in Denmark, a number of medium sized customers, including hospitals, an airport and large manufacturing companies offer their emergency power units for use by the System Operator. Both demand reductions and emergency power units are despatched from the control room of the System Responsible who acts as Aggregator. Customers are paid around €25 for each MWh they make available with the service expected to be in use 10-30 hours each year. A total power of 28 MW has been made available by this mechanism.

Overall, the general range of payments for delivering Fast Response and Standing Reserve in the participating country markets is between €70 and €500 per MWh. A figure of €280/MWh has been adopted as an average payment so as to compare aggregated payments with the cost of implementing smaller customer DSB. The €280 figure varies significantly across markets in different countries depending on the generation capacity situations. Variations occur for different times of the year due to capacity shortages and the cost of generation plant. These times are not always due to weather and the likelihood of system maximum demand occurring but also at other times of the year because of plant shortages as a result of maintenance outages, etc. It also varies in different markets within countries especially as a result of notice times required, i.e. “fast response” market or “standby” market. However, it is a useful figure against which to consider payments for delivery of a range of smaller customer demand side changes. This allows ball park estimates to be made regarding the potential viability of smaller customer DSB.

The payment of €280/MWh means that the more hours each MW is called on to be “available” and “turned down”, the larger the total payment.

The costs of providing a range of services using communications between smaller customers, Service Providers and Service Aggregators have been estimated in IEA DSM Task 2 project, “Communication Technologies for Demand Side Management”. The costs of providing 21 services using different communication media were estimated for the different businesses and arranged across a customer population to drive a ball park cost per customer. The average cost per customer per annum for the Service Provider business was €25. The average cost per customer per annum for the Service Aggregator business was €60. The average cost per customer per annum for the Communication business was €28. The average cost per annum per customer therefore for providing the range of services was €59. The costs of providing a range of services include relatively fixed infrastructure costs and costs which are dependent on the number of services. This is particularly the case for different services, some of which use one way and some two way communications. In order to reflect these issues and the limited services required for DSB and TOU pricing delivery, a cost per customer of €50 per annum has been used in this comparison of costs and benefits.

The analysis in Chapter 3 identified that approximately 75% of smaller customer demand contributing to system peak in Spain could be classed as relatively unobtrusive if it were “turned down”. The diversified contribution to system peak demand by each smaller customer in Spain was shown to be 0.57kW resulting in an unobtrusively managed component of 0.43kW.

If the 0.43KW of unobtrusive demand change is “available” for reduction in non electric heated homes then, 50/0.43 x 0.28 = 415 hours of demand reduction per annum is required in order to break even with the control and two-way communication infrastructure costs of €50 per year.

Applying DSB to deliver demand changes of 2.5 kW per customer in Finland as described in Chapter 3, requires 75 hours of “turndown” each year to offset the infrastructure costs. However, it is important to consider these figures in the right context. A comparison has been made between the full capital and operating costs of DSB communication and control infrastructure (€50 per year) and the marginal cost of scheduled generation represented by the 0.28/KWh. A full comparison of the capitalised cost for both generation and DSB infrastructure carried out in Task 2 report showed demand side changes to be lower cost.

Targeting the relatively unobtrusive demands associated with high energy customers and those with direct electric heating offers the most economic scenario. This targeting would focus on possibly, water heating, air conditioning, embedded generation, direct showers, refrigeration and saunas with lighting also a possibility. This focus on high demand customers could deliver in many countries, possibly 1.5kW of demand available for DSB. If only a single or possibly two energy controllers were required per household and one way communication used to deliver the service, lower costs would be possible. If the 1.5kW demand could participate in being "available" and turned down for say 30 hours per year, the 45kWh would attract 45 x 0.28 = €12.6 in payment. At 10% discount rate for 10 years, this would support a capital expenditure on controllers of 12.6 x 6.14 = €77. A single demand switching controller based on one way communication could probably be made available in volume for this cost.

These financial savings and benefits are small and unlikely to provide an incentive to customers to participate. However, additional savings may be possible due to reduced energy costs with TOU pricing. It was also indicated in the Subtask 2 report, "Time of Use Pricing for Demand Management Delivery", that customers can be motivated by other issues such as the environment providing that additional costs are not incurred.

These estimated, demand change implementations assume that all the demands can "turndown" in sufficiently rapid a time and be sustained for sufficient duration that an average of €0.28/KWh is available for payment. For the unobtrusive demands it is possible for rapid response times to be achieved using appropriate control technology. For obtrusive demand changes it is likely that customers will require prior notice of possibly a day or half a day ahead in order to reschedule their lives before "turndown". This will reduce the value of the demand change potential of obtrusive end use demands. However, it may still be possible to have rapid "turndown" even though notice of the probable event is provided many hours before.

A major issue therefore for the viability of DSB and Demand Response for smaller customers, centres on whether customers will accept the identified demand "turndown" for the relatively large numbers of hours required and whether that number of hours and the duration of each event have sufficient value to System Operators.

7 Potential Barriers for Smaller Customer DSB

The previous Chapters have shown that DSB and "turndown" of smaller customer demand require a collection of processes to be in place in order to be viable. These processes are:-

- Motivating customers to participate (obtrusive/non obtrusive demand changes)
- Aggregation of collections of smaller customer demands.
- Validation of "available" demand
- Validation of "turned down" demand

- Payments for demand "turndown" participation
- Accommodating dynamic demand changes in "profile" settlement structures
- Persuading System Operators that smaller customer demand response is reliable, predictable and secure
- Development of the Aggregator business case
- Cost effective implementation technology.

7.1 Motivating Customers to Participate

Motivating smaller customers to participate in Demand Side Bidding mechanisms will be a significant challenge. This will be true particularly for obtrusive demand side end uses where customers experience obvious inconvenience. Field trial studies described in Chapter 4 show that there is a willingness by customers to participate, in principle, with energy saving/ environmental programmes. The results of customer involvement must involve some financial reward but it may not need to be large. Larger reward for customers is likely to be required for obtrusive demand change participation especially if no override is allowed. Continuous marketing of DSB programmes is also likely to be needed.

7.2 Aggregation of Collections of Smaller Customer Demands

Minimum demand blocks of several MW are required by System Operators for Demand Side Bidding, which preclude smaller customer participation as individuals. Consequently, aggregation processes are required of at least thousands of smaller customers in order to achieve adequate block size. Technically this is not a difficult problem using broadcast communication technology to access customer control equipment associated with individual end uses. It is likely that communication and control infrastructures would be organised and installed by Aggregator businesses with the facilities used by Aggregators to provide demand management services to System Operators and Suppliers. Aggregation of demand may have to be carried out in zoned blocks on a geographic basis so as to assist with "validation" at grid metering point and avoid transmission constraints.

7.3 Validation of "Available" and "Turned Down" Demand

Validation of "available" demand is required in order that System Operators can be confident that the demand change potential is actually available to be "turned down" if and when required. It is a critical activity in order to allow the demand side to fully participate in electricity markets. It is unlikely that "validation" for smaller customer demands can use time of use metering systems presently used for larger customer demand bidding. Successful trials have been carried out of remotely switching smaller customer demands using broadcast radio signals. These trials have shown that "available" demand can be estimated by reference to the actual control signals transmitted to customers. They have also shown that validation of “turndown” can be approximated by reference to grid metering combined with modelling if the demand block size switched it reasonably large. It seems likely that these methods could be refined to include time of year, weather data and time of day to obtain more accurate estimates of “available” demand.

7.4 Payment for Demand Participation

Payment for participation in bidding demand curtailment by smaller customers is important for its viability. Financial payments could be made to participating customers by means of the tariff via Suppliers. Suppliers would then contract Aggregators to deliver the service. It may also be possible for Aggregators to offer the service directly to customers and reward customers with direct payments. The Aggregator could seek the cheapest Suppliers for customers. However, it is likely that any payment scheme needs to be supported by vigorous marketing campaigns promoting the environment and energy saving value of customer participation in demand side bidding. Payments to participating customers are unlikely to be large with the present levels of reward available in markets. However, these levels may well increase if forecast generation and network capacity shortage actually take place.

7.5 Accommodating Dynamic Demand Changes within “Profile” Settlements Structures

Another issue which needs to be considered for smaller customers is that financial settlement among Suppliers in competitive markets uses customer profiles to apportion demand against time for each Supplier. Suppliers have a mix of customers – some with time-of-use (TOU) metering and others whose Time of Use loads are determined using ‘profiles’. Thus, for each trading period, the total demand for which each supplier must purchase electricity is the sum of his TOU metered demands and estimated profiled demand. The profiled sum error is reconciled, amongst all suppliers, against the metered totals at the major network metering (grid supply) points. This settlement process, taking account of any DSB actions, is simplest for TOU metered customers, but incurs higher costs in terms of metering, communication and control, although the remote metering with 2-way communication will be more common in the future in some countries. The “dynamic” demand profiles generated by demand “turndown” will introduce errors in “profile” settlements systems now in place in most competitive markets. Supplier settlement systems rely on statistically stable profiles for smaller customers. If wide scale participation in demand side bidding occurred, new profiles may be required, possibly including variables to take account of the actual demand control signals issued.

It may be feasible to reconcile DSB for ‘profiled’ consumers but requires the establishment of modified ‘profiles’ to account for the DSB actions. However these profiles may be corrected if the demand “turndown” request signals are also input to settlement systems.

7.6 Persuading System Operators that Smaller Customer Demand Response is Reliable, Predictable and Secure

Developing demand side bidding and “turndown” for smaller customers to provide reliable and predictable demand changes for use by System Operators and Suppliers is a significant challenge. Reliable demonstration of “available” and “turned down” demand is needed in order for the demand side to displace generation. However, in order to include the statistical nature of smaller customer demand and small scale generation into markets, risk assessments need to be included and managed by Aggregators within portfolios of demands.

7.7 Development of the Business Case

Comparisons of costs and rewards for smaller customer demand side participation in electricity markets was carried out in Chapter 6. This showed that in order for break even to occur, the demand side needed to be “turned down” for many hours per year. Technically, demand side bidding and “turndown” are feasible with existing technology. The critical issue is whether customers will allow demand “turndown” to take place for a sufficient number of hours per year in order for the payments to offset the infrastructure costs. The most attractive business case will target electric heating and high demand customers first because the infrastructure cost per customer will be similar for both high and low demand customers.

According to a temporary law in Sweden until 2008, the System Operator is required to purchase defined amounts of capacity reserves, some of which must be demand” turndown”. The goal for Sweden is that capacity reserves will be organised by the market itself without the help of the System Operator and that a common solution will be agreed within the Nordic market.

7.8 Cost Effective Implementation Technology

Demand Side participation in markets by means of flexible switching of customer demand and allowing it to be bid in competition with generation requires the use of communications and control technology. Switching of storage, space and water heating by remote, broadcast communications has been carried out for many years in many countries. These switching processes use radio, power line or telephone communication media. Access to the customer demand is usually through a single point of control in customer houses which removes the need for “in house” communications.

Generally the switching regime is non obtrusive. More recent trials have advanced the control to several points within customer premises, to access items such as heating and cooling thermostats where the set points can be changed. Communicating control nodes need to be included in thermostats and end use devices. The cost of these items is critical to the viability of smaller customer DSB.

Systems can be implemented using communication buses in customer houses and linked to external communications using gateways or directly using external communication to individual devices. Both methods have their strengths and weaknesses. TOU metering is not an essential requirement for delivering DSB for smaller customers as long as, once contracted, implementation of demand switching is not optional and no override is possible.

Subtask 2 report, "Time of Use Pricing for Demand Management Delivery", estimated the communication and control costs for remote switching of a collection of end uses in a customer premises using two-way communication as approximately €50 per year. One way communication and simple "on/off" switching would enable lower cost control to be implemented for a reduced number of nodes.

8 Conclusions

The study has shown that there is a role for smaller customers to bid demand to assist system operation, improve supply security and reduce supply costs. Savings in CO2 may also be possible. Conclusions from field trials carried out in participating countries show that there is a positive attitude among many smaller customers to saving energy and making financial savings provided the inconvenience is small. Incentives need not necessarily be financial as long as additional costs are not incurred by customers. Environmental incentives and the belief that they are doing the right thing are sufficient for many customers in some countries.

Aggregation of smaller customer demands into blocks of several MW is a requirement for DSB participation. The study has shown that unobtrusive as well as obtrusive management of end uses of energy may be possible in order to enable smaller customers to be "available" for automatic "turn down" of demand. No real understanding has been obtained as to whether and to what extent smaller customers would be prepared to accept end use inhibits for relatively short durations for everyday appliances. Automatic temperature changes of the space environment and of refrigeration appliances are regarded as unobtrusive and the most likely energy end use demands, the management of which could be accepted by customers. The management of washing machines and other white goods is technically feasible but is relatively obtrusive and less likely to be acceptable to customers. The management of lighting by making small changes to illumination levels would be obtrusive but may be accepted by customers. However, the extent to which customers could be influenced by extensive marketing and promotion so as to allow management of these end uses and the incentives required are not known. If smaller customers can be motivated to participate in demand management of everyday end uses of energy, a demand of between 0.5kW and 3kW per customer is potentially “available”.

The technical feasibility of carrying out DSB for smaller customers has been demonstrated using two way communication. Rewards and costs for customer participation in DSB have been presented based on payments made to larger customers and results of earlier communication studies. These show that the economic case for smaller customer DSB is marginal using two way communication to achieve validation. Two way communication allows validation that customers are fully participating in DSB and meeting their contractual obligations and agreements. One way communication is significantly lower in cost than two way communication but requires validation of customer participation to be carried out using statistical methods. This is likely to require that customers, once contracted to deliver automatic demand changes, cannot override that option at short notice but it also removes the requirement for TOU metering.

The study has identified potential barriers to implementing wide scale DSB for smaller customers. These include the making of a viable business case which provides cost effective mechanisms for validating demand “available” and “turned down”. The use of Aggregator businesses, possibly linked to ESCOs, may be the way forward. They also include the requirement to make a powerful marketing case to persuade smaller customers to participate. This study provides the system infrastructure and control requirements likely to be needed in such a business evaluation.

Profile settlements used in competitive supply markets will be impacted through to the use of dynamic demand changes resulting from System Operator and Supplier “turndown” requests. This may require more sophisticated settlement systems in order to deal with these variations.

An important factor in the acceptability of DSB schemes in system operation and supply contract balancing is that market players have confidence that contracted demand is “available” for management and will “turn down” when requested. This confidence can only be provided by demonstrating that aggregated, statistical demands and embedded generation from large numbers of smaller customers can be predicted with reasonable accuracy.

9 Recommendations

The study and has identified issues and barriers to the implementation of DSB for smaller customers. In order to contribute to reducing these barriers, further study is required to:

- Quantify the willingness of smaller customers to participate in DSB and remote management of individual energy end uses.

- Develop mechanisms for low cost validation of demand “available” and “turn down”.
- Quantify the impact and identify possible solutions to enabling dynamic profiles to be used with “profile” settlement systems.
- Develop and appraise technical and business architectures for smaller customer DSB. This includes business models to define how to market packages of measures and roll out DSB enabled end uses of energy and their management.

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