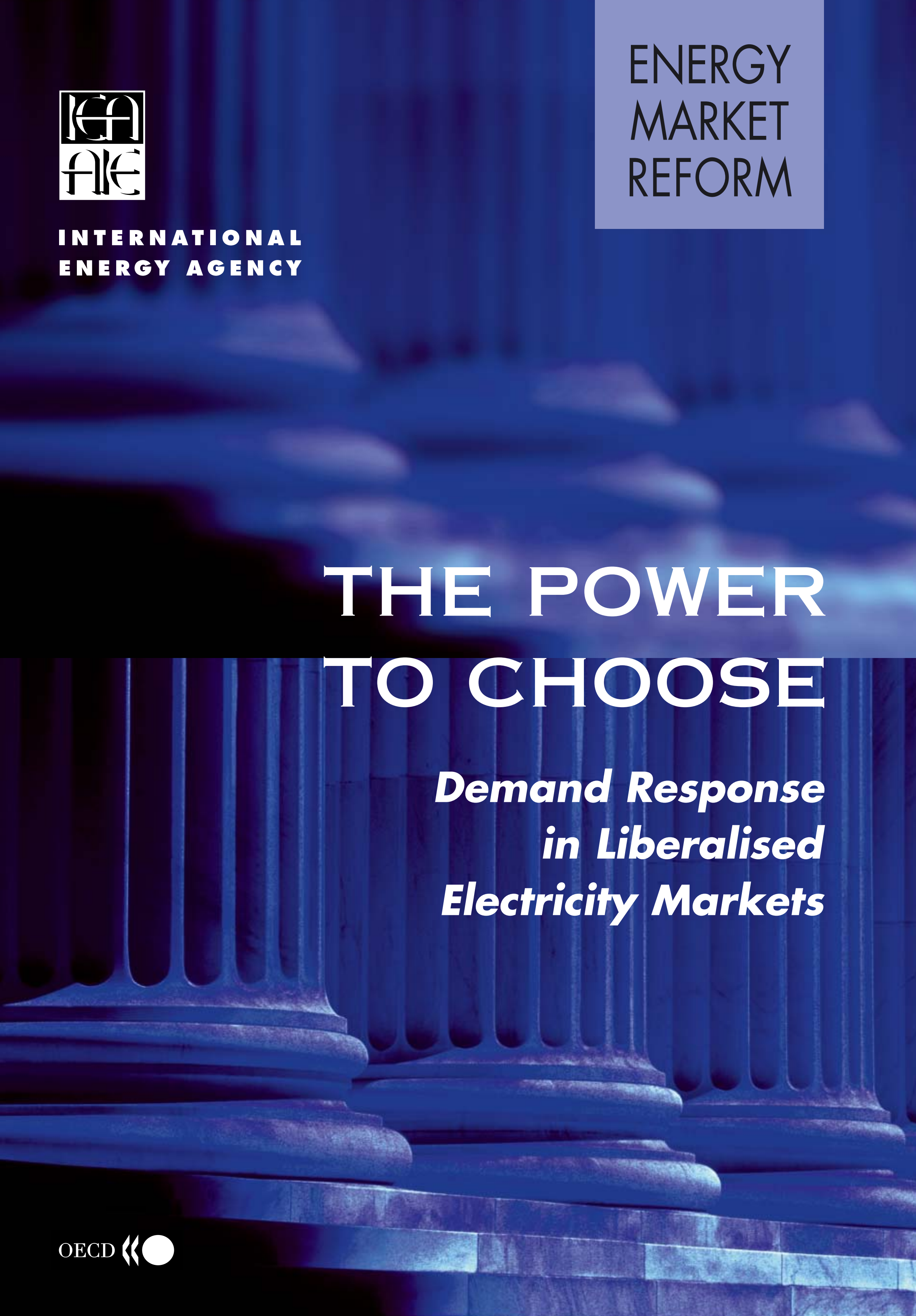

INTERNATIONAL ENERGY AGENCY

ENERGY MARKET REFORM

THE POWER TO CHOOSE

Demand Response in Liberalised Electricity Markets

OECD

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Demand Response in Liberalised Electricity Markets

OECD

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The International Energy Agency (IEA) is an autonomous body which was established in November 1974 within the framework of the Organisation for Economic Co-operation and Development (OECD) to implement an international energy programme.

It carries out a comprehensive programme of energy co-operation among twenty-six* of the OECD's thirty Member countries. The basic aims of the IEA are:

- to maintain and improve systems for coping with oil supply disruptions;
- to promote rational energy policies in a global context through co-operative relations with non-member countries, industry and international organisations;
- to operate a permanent information system on the international oil market;
- to improve the world's energy supply and demand structure by developing alternative energy sources and increasing the efficiency of energy use;
- to assist in the integration of environmental and energy policies.

** IEA Member countries: Australia, Austria, Belgium, Canada, the Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Japan, the Republic of Korea, Luxembourg, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, the United States. The European Commission also takes part in the work of the IEA.*

ORGANISATION FOR ECONOMIC CO-OPERATION AND DEVELOPMENT

Pursuant to Article 1 of the Convention signed in Paris on 14th December 1960, and which came into force on 30th September 1961, the Organisation for Economic Co-operation and Development (OECD) shall promote policies designed:

- to achieve the highest sustainable economic growth and employment and a rising standard of living in Member countries, while maintaining financial stability, and thus to contribute to the development of the world economy;
- to contribute to sound economic expansion in Member as well as non-member countries in the process of economic development; and
- to contribute to the expansion of world trade on a multilateral, non-discriminatory basis in accordance with international obligations.

The original Member countries of the OECD are Austria, Belgium, Canada, Denmark, France, Germany, Greece, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom and the United States. The following countries became Members subsequently through accession at the dates indicated hereafter: Japan (28th April 1964), Finland (28th January 1969), Australia (7th June 1971), New Zealand (29th May 1973), Mexico (18th May 1994), the Czech Republic (21st December 1995), Hungary (7th May 1996), Poland (22nd November 1996), the Republic of Korea (12th December 1996) and Slovakia (28th September 2000). The Commission of the European Communities takes part in the work of the OECD (Article 13 of the OECD Convention).

FOREWORD

Since the early 1990s, the IEA has produced a series of studies on electricity market reform, paying particular attention to reforms on the supply side of the market, to regulatory institutions and to the impacts of reform on energy security and economic efficiency. Our monitoring of the progress of reform has suggested that more work needs to be done if liberalisation is to deliver fully on its potential to create long-term reliable, secure and cost-efficient electricity markets.

This latest study considers the proposition that the demand side is not actively participating in the price-setting process in many liberalised markets, whether due to on-going price regulation, poor incentive structures or the relative immaturity of the market players and institutions. This has contributed to a number of the problems we have seen in liberalised markets – blackouts, system failures, excessive price volatility and suggestions of market manipulation – all of which have had wider economic and social consequences for our member country governments, in addition to generating some spectacular corporate failures.

This publication encourages IEA member governments to facilitate a greater demand response in electricity markets, essentially through more efficient and innovative pricing, and appropriate market design and regulation. As well as quantifying the multiple benefits of a more responsive demand-side, this publication provides guidance to policy-makers, regulators and market participants on how these benefits can be captured through balanced market design, investment in technology, market-based policy delivery and prudent use of regulation where necessary.

Ultimately, I hope that greater attention to demand response by member governments will redress some of the observed shortcomings of liberalised markets, and help to restore confidence in the model of competitive electricity markets around the world.

This book has benefited enormously from the contributions of the End Use Working Party and its contribution to the IEA Demand Response Workshop held in Paris, in February 2003. The author of this book is Michael Jones with direction provided by Phil Harrington and contributions from Peter Fraser. This book is published under my authority as Executive Director of the International Energy Agency.

Claude Mandil
Executive Director

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EXECUTIVE SUMMARY

Liberalised electricity markets need a strong demand response capability

In efficient markets, prices are formed through complex interactions between buyers and sellers: the demand – and supply-sides of the market. In today's liberalised electricity markets, most buyers do not participate actively in the price-setting process. As a result, prices fail to play their normal role of balancing natural swings in supply and demand, leading to excessive instability.

Demand response refers a set of strategies which aim to bring the demand-side of the electricity market back into the price-setting process. Demand-side resources are variable loads created as customers adjust their demand in response to price signals. The introduction of demand-side resources into constrained networks will significantly dampen the price peaks often seen in wholesale markets today, reducing costs and risks for all market participants. By clipping price peaks, demand response will also lead to lower wholesale prices on average and a more efficient market.

Demand response (also known as load – or peak-shifting, but here meaning shifting attained through pricing strategies) presents a viable alternative to traditional supply-side remedies in constrained wholesale markets. It offers a highly-flexible and naturally-distributed resource to network operators, and reduces the need for investment in peak supply capacity. Critically, demand response enhances security, particularly on constrained networks, as higher concentrations of demand are typically located at network nodes where congestion is high and network security most vulnerable.

Concentration on the supply-side of the market and the abuse of market power continue to trouble the efficient operation of many liberalised electricity markets. Most competition models in OECD electricity markets overlook the potential contribution of increased demand response to this problem. Yet market power abuses can be reduced either by reducing concentration on the supply-side of the market (e.g. by requiring divestiture by dominant firms of some of their generating plant) or by increasing the elasticity of demand relative to price – and this is what demand response does. In fact, doubling the price elasticity of demand would have the same impact on prices as halving the concentration on the supply-side, yet the former may be considerably easier to achieve.

Finally, and notwithstanding the primacy of its economic and security benefits, demand response may also generate important environmental benefits. First, demand response has been shown to deliver a net reduction in consumption, directly reducing emissions. Second, where demand response shifts consumption in time, the environmental impact will be more complex, governed by the mix of fuels and the emissions profiles of the base-load and peaking displaced by the demand response. Although the second impact is harder to quantify, it is possible that both contributions will deliver net positive environmental benefits, particularly where base-load power plants are more efficient and/or less polluting than intermediate and peaking plants.

Current market designs do not enable demand response

Demand response in existing markets is typically low, since market participants lack both the incentive and the means to respond. Regulated retail prices, out-dated metering technologies, a lack of real-time price information reaching consumers, system operators focused on supply-side resources and a historical legacy in which demand response was not considered important – all of these factors combine to produce the low levels of demand response seen in electricity markets today.

Despite this, studies of price responsiveness, or elasticity, in electricity markets show that customers can and do respond to price signals, but only when the conditions are right. With dynamic pricing strategies, where at least some component of the real cost of electricity supply[1] is

1. Retail electricity prices reflect two components that should be priced separately: the electricity commodity and the insurance premium that insulates customers from price variations.

revealed, consumers do respond. Indeed, a key conclusion of this study is that a combination of price increases and decreases, varying over a day, week or season in response to underlying market conditions (so-called time-of-use pricing), can yield significant demand responses during critical time periods, as well as an overall reduction in energy demand. This can be compared to policy measures that seek to raise the average level of electricity prices, in order to restrain demand, which have shown themselves to be unpopular and ineffective, especially when market prices are low to begin with.

Customers deserve more pricing options and greater choice

Some consider electricity supply to be a commodity; however, its cost and value are constantly changing over time and according to the end-use application. Economic efficiency in competitive electricity markets requires that customers are offered a variety of pricing options, to efficiently reflect these variations in cost and value. At the same time, it is not necessary – to capture the benefits of demand response – that all consumers are exposed and respond to real-cost prices. Significant economic gains can be realised with relatively small amounts of response – is some cases, wholesale prices could be reduced by up to 50% with as little as a 5% demand response capability. Most importantly, demand response offers real financial savings for electricity users. It has been estimated, for example, that incorporating demand response into the United States market, with dynamic pricing, would lead to savings of between $10 billion to $15 billion per year.

As retailers look for new ways to manage risk and retain customers beyond conventional price-reduction offers, the need for innovation in end-use pricing will become more evident. Permitting customers to face some component of the underlying variability in electricity costs can improve economic efficiency, increase reliability and reduce the environmental impacts of electricity production. At the same time, those customers who prefer fixed tariffs should continue to have access to this option in the market, although they should expect to pay an 'insurance premium' as part of this fixed tariff in return for being fully covered from price risk.

Significant investment is needed

Without the appropriate technology and communications infrastructure in place, demand response will not be enabled. To enable markets to communicate the variable value and cost of electricity supply, a significant investment will be required in intelligent metering and communication infrastructure. The challenge is neither the availability of such technology nor its cost – great progress has been made in these areas in recent years. Rather, the challenge is that current market designs, even those incorporating competitive metering service markets, fail to recognise and correct the barriers to large-scale investment in such technology. The barriers include:

■ **Investment cycles.** In order to provide economic payback, consistent with the shareholder expectations of privately-owned retail or service companies, the investor requires that an asset be "working" (in use) for its economic life. Traditional metering investments, and the cost recovery mechanisms which support them, assume an economic life for the asset of up to 20 years. But in competitive markets, potential investors are now faced with a more fluid customer base and an uncertain regulatory regime, and thus they cannot be assured that an intelligent metering asset will remain "working" for its expected life. Governments need to evolve a regulatory regime which provides adequate security for investment in an intelligent metering and communications infrastructure.

■ **Split incentives.** In a competitive market, the potential benefits of an intelligent metering and communication infrastructure are split between the end-use customers (who benefit from both the potential to regulate demand in response to real price signals, and hence save energy costs, and increased network security); other customers (who benefit from increased security, whether they pay for this benefit or not); the retailer (who benefits from the potential to reduce purchasing costs from the wholesale market and to offer better risk-managed retail products); the distribution and transmission service providers (who benefit from better congestion management and lower system costs); generators (who benefit from better matching of capacity to load, reduced "spinning reserve"); and systems operators (who benefit from increased system reliability and lower overall costs). This creates a *prima facie* case for a policy response, to ensure that the diverse benefits of demand response are not lost. Without some collective action, and in a competitive market-place, no one actor may be able to capture enough of the benefits to justify a private investment.

■ **Scale effects.** Reduced costs, and hence more cost-effective implementation, come with scale. This does not apply only to metering, but also to the costs of program design, marketing, implementation, education, billing and customer services. Where the electricity market design provides a reasonable and fair mechanism for investors to manage the risk of stranded (demand response) assets, it may then be possible for large retail or service companies to realise these scale benefits.

With few exceptions, liberalised markets have shown that these hurdles will prevent significant investment in advanced metering infrastructure and thus impede the delivery of retail innovation and demand response. In some cases, however, regulators have taken the view that demand response offers significant public benefits, including enhanced system reliability, reduced emissions and lower prices for all, warranting intervention in the market[2]. Reviewing the case, we conclude that policy intervention is necessary if the potential for increased demand response is to be realised.

Governments and regulators have a key role to play

Although the potential benefits of dynamic pricing are large, so too are the barriers to its widespread adoption. While regulators should not force consumers to face dynamic pricing, neither should they make it difficult for them to do so. Well-intentioned regulatory policies, designed to protect consumers from the vagaries of market prices and wholesale market volatility through price caps and standard default rate designs, have inadvertently reduced retail price innovation. Such policies can prevent retailers from creating a portfolio of pricing options which would

2. *Essential Services Commission – Installing Interval Meters for Electricity Customers – Costs and Benefits Position Paper – November 2002.*

offer customers a greater range of price and service options, while enabling them to re-balance risk and reduce overall costs.

Regulators may therefore need to review their decisions on standard-offer rates that may be set at a level and in a form that prevents innovative new supply offers to enter the market. These decisions may also provide customers with no incentive to look elsewhere for a better deal or to use electricity more efficiently.

Since the benefits of demand response are widely dispersed amongst different market players, it is clear that markets will not develop a meaningful demand response capacity without facilitation by governments. Governments and regulators need to form a clear picture of the degree to which demand response could deliver economic benefits – both public and private – in their own countries, set against their own local and regional public policy objectives.

Given the public benefits of demand response, governments need to ensure that the required investment costs can be recovered from the wide set of beneficiaries in the market. This study reveals that there are not only private economic gains available to direct participants, but also many public good and societal benefits which will not register in a normal business investment model. Government policy needs to be aligned to the realities of the investment environment and capable of recognising how benefits are accrued, in which quantities and to which parties. Governments need not make investments in demand response capability themselves but, where the societal and public goods benefits have been measured and quantified, mechanisms such as public benefit funds, cost-recovery mechanisms or tax relief may be necessary to stimulate private investment.

Government and regulators should review their price regulation and capping measures and their incremental cost recovery mechanisms, to ensure they are not impeding demand response. There is a balance to be struck between the public-protection role of regulated price-setting and the economic benefits of competition and increased price transparency. Where price discrimination is considered necessary as a matter of public policy, for example to provide for socially-disadvantaged communities and the fuel-poor, technology investments will provide additional and necessary information and data to ensure programs are effectively targeted.

Measuring and evaluating demand response capability will provide a baseline against which specific objectives or targets can be set. Some OECD markets, specifically Canada, Australia, New Zealand and the United States, have begun this process at both federal and state/regional levels. Regulators should be prepared to support or facilitate programs and pilots which provide market-specific insights into the potential of demand response, and to the extent possible, allow the market to determine and adopt appropriate enabling rules and business procedures.

Finally, market designers and regulators should ensure that demand-side alternatives are considered on an equal merit to supply resources when planning network and system upgrades. Full economic consideration of the value of demand-side resources and the investment required to achieve them is often complex, but the learning process has begun and the evidence of the benefits available is now coming in.

INTRODUCTION

Objectives and Scope

The prime objective of this publication is to review the role that enhanced demand response could play in contributing to the efficiency and security of liberalised electricity markets. Analysis is focussed on electricity markets which have either completed, or are well down the path toward, full market restructuring. Monitoring such markets during the liberalisation process will enable valuable policy lessons to be learned.

The study provides insights into the current state of play regarding demand side responsiveness in selected liberalised electricity markets, recognising both commercial and regulatory aspects of market operation. Consideration is then given to the use of various policy instruments in the continued development of liberalised markets and the respective linkages to climate change policy.

Finally, a detailed examination of the role of pricing is performed to determine its contribution to the economic, environmental and energy security benefits which could result from the wider deployment of demand response technologies.

What is Demand Response?

Demand response refers to a set of strategies which can be used in competitive electricity markets to increase the participation of the demand-side, or end-use customers, in setting prices and clearing the market. When customers are exposed in some way to real-time prices, they may respond by a) shifting the time of day at which they demand power to an off-peak period, and/or b) reducing their total or peak demand through energy efficiency measures or self generation. Alternatively they may choose not to respond at all and pay the market price for electricity instead. To the extent that they do respond, the profile of demand in the market will be smoothed which, in turn, feeds back into prices, clipping the peaks significantly and, to a lesser degree, lowering average prices. The net effect of the demand response is to ease system constraints and to generate security and economic benefits for the market as a whole.

To put demand response in context, we first need to review the essential characteristics of electricity markets, including how – in liberalised markets at least – prices are formed. The maintenance of a secure and reliable electricity system depends upon matching the supply available to the demand or load at all times. Since there are seasonal and weather-related variations in electricity demand, and since electricity cannot be stored in large quantities, it is necessary to plan supply availability according to the highest forecast demand in any given period, plus a margin for error. If this were not done, supply interruptions in the form of brownouts and blackouts would be commonplace, causing considerable economic damage.

In vertically-integrated electricity systems, supplies are maintained by a monopoly provider who has the responsibility to ensure that adequate generating capacity is available. Prices are generally regulated and therefore play little or no role in signalling when electricity is scarce. In liberalised systems, by contrast, the function of balancing supply and demand is performed in "market time[3]" or "real-time", normally through a wholesale electricity market, where information about the supply and demand balance (currently, and in the near future) is signalled by electricity prices. Electricity market liberalisation policies were introduced with the intention of creating a reliable, economically efficient electricity sector, including by increasing transparency in price setting. However, the evidence to date suggests that this process is far from complete.

Generally, efficient market prices are formed by interactions between the supply side (the sellers) and the demand side (the buyers). This interaction determines the value of supply[4] at any point in time. However, in liberalised electricity markets, nearly all retail customers are exposed to prices that are fixed for relatively long periods, regardless of the supply-demand balance in the market. Under such conditions, the customers have no incentive to vary their consumption in response to

3. *Market Time refers to the smallest interval of market trading. Periods are typically 60, 30 or 15 minutes.*

4. *In this context energy supply includes the electricity energy and the reliability, or security of the service.*

actual market conditions, nor can they provide a natural price-led response, reflecting their real-time valuation of energy supply. These conditions give rise to a type of electricity market design failure, often referred to as the "wholesale-retail disconnect", which may be evidenced in excessive price volatility.

The demand for electricity, and the cost of its supply, can vary substantially from hour to hour, leading to price changes of up to a factor of ten within a single day. A certain degree of price volatility should be considered normal, resulting from the "real-time" nature of electricity supply-demand balancing. However, excessive volatility may be created or exacerbated by capacity constraints, scheduled and unscheduled outages, transmission bottlenecks, "peaky" demands and, potentially, the exercise of market power by generators or traders. Conventional network operation has focused to date almost exclusively on supply-side solutions, such as increased generation and transmission infrastructure, to constrain excessive and inefficient pricing.

Against this background, the aim of this publication is to show how increased demand side participation can reduce the risks of these events in liberalised electricity markets, by providing an effective counterbalance to the dominant role of the supply side in price determination.

Markets for demand response in liberalised systems can operate in two ways[5]:

■ **System led.** The system operator, or a service aggregator or agent, signals the demand-side customers that there is a requirement for load reduction or shifting. These are often reliability-based programs where the prices are set by market or system operator (wholesale markets).

■ **Market led.** The customer responds directly to market pricing signal, causing behavioural or systematic consumption change. Prices are set by market mechanisms (interaction between wholesale and retail markets).

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5. Illustration – The Load Response Program (LRP) provides incentives for New England Pool Participants to reduce their electricity demands during peak power periods according the following designations:

*• The **Demand Response Program** which compensates users for reducing consumption at ISO-NE's direction (System Led); and*

*• The **Price Response Program** which compensates users for monitoring and controlling their consumption in response to real-time market prices. (Market Led).*

A final note on the definition of demand response relates to a more traditional and somewhat related term, Demand Side Management (DSM). Whereas demand response refers to the use of market-based prices to influence the timing and level of demand, demand side management refers to a broader set of measures aimed at increasing end-use efficiency and/or shifting peak load, but not usually through market-based pricing strategies. The two approaches are not in conflict with each other: in fact, increasing demand response will establish economic incentives which will support the implementation of demand side management activities, such as home insulation, energy efficient lighting and conservation programs.

Demand Elasticities

Elasticity can be defined as a correlation between two variables, e.g. price and demand. When price increases demand typically decreases, and the size of the decrease is determined by the elasticity – in this context, the price elasticity of demand. In empirically-oriented economic research, the concept of elasticity is critical to understanding to what extent demand will respond to changing prices, for example in the electricity market. Of course, individuals have different price elasticities of demand for a given product, so averages are generally sought in such empirical work. Elasticities can change as a result of changes in household or business income, new substitution possibilities and changes in the relative prices of electricity and other goods and services. Different types of elasticity are shown in Table 1 below.

Table 1

Elasticity Types

Elasticity Type	Definition
Income elasticity	The change in demand for electricity per % change in income
Own-price elasticity	The percentage change in the demand for a given percentage change of price of the electricity
Elasticity of substitution	The percentage change in the relative consumption of two goods as a consequence of a change in the relative prices of the goods.
Cross price elasticity	The percentage change in demand for good i as a result of a percentage change in the price of good j[6].

6. According to a survey in the USA the cross-price elasticity between electricity and natural gas in the households is 0.20. That is, if the price of electricity increases by 1% the demand for natural gas will increase by 0.20% (Salvatore, 1993). Elasticity of substitution and cross-price elasticity are closely related concepts.

The extent to which demand will respond to price variations is typically modelled using own-price elasticity demand coefficients. Understanding these is critical to evaluating any time-variant tariff product or demand response program, as it provides means of measuring and forecasting the size of the demand adjustments that come about as a result of price changes on the market. Incorporating income elasticity requires a more detailed knowledge and segmentation of the consumer markets, information to which utilities may not have access.

Studies of own-price elasticities in electricity markets typically yield coefficients in the range of 0.1 to 0.2 in the short run, and 0.3 to 0.7 in the long run. This means that for a 10% change in the price of electricity, there will be a 1%-2% change in demand in the short run and a 3%-7% change in the long run. Long run estimates allow time for the consumer to adjust their capital stock – home appliances and end use products – in response to the price signals, whereas in the short run estimate, consumers are assumed to have a fixed capital stock. In the context of electricity market elasticities, short run typically refers to periods of less than two or three years, while the long run may refer to periods of 10 to 20 years.

These studies indicate, therefore, that the demand for electricity is traditionally relatively price inelastic, or unresponsive, particularly in the short run. In this situation, a (regulatory) price increase would trigger a decrease in demand which would be relatively smaller than the increase in price – therefore the consumer's total expense for the good in question would increase (Fog, 1992). It is for this reason that electricity market regulators have tended to be wary of using price as a tool to modulate demand.

However, the true potential for demand response cannot be judged from such historical estimates. To begin with, responsiveness to price changes is rarely symmetrical or linear. They may not be symmetrical, in that a 1% increase in prices may lead to a larger percentage fall in demand than would a 1% fall in prices increase demand. Since demand response exposes customers to both higher and lower prices, the net effect is unclear. Second, elasticities may not be linear, in that the percentage response to a small price change may be smaller than the response to a large price change. This is in part because as price rises relative to income, the incremental effect of income elasticity and product substitution will become significantly more notable (Laitner, 1999). Empirical estimates of elasticities are normally made for small, incremental price changes. However, demand response programs may expose customers to larger price changes, both increases and decreases.

Further, the historical estimates of price elasticity for electricity derive from regulated or time-invariant markets, and therefore examine only the effect of changes in average prices. Prices are assumed not to vary in the very short run (ie, on an hourly, daily or even seasonal basis). But during certain time periods, the economic value of a demand response (load reduction) to the consumer, retailer and market operator may be significantly higher than the average price paid for electricity. Therefore, "short run" coefficients of elasticity (as noted, where "short run" means up to two years) mask the potential for much higher elasticities which may occur over the much shorter time periods of interest to demand response programs. Critically, the short run estimates do not reflect the potential for short term behavioural changes on the part of the consumer (i.e. switching a load on or off). Yet it is precisely these sorts of actions ('very short run elasticities') that demand response programs target. Finally, in a well-designed demand response program, the increase in electricity costs to consumers during a peak period are more than offset by reductions in cost in off-peak periods.

In sum, demand response programs aim to change price elasticities of demand for electricity. Therefore, we cannot treat historical estimates as valid indicators of the scope for demand response in liberalised electricity markets.

Significantly, where elasticity studies have been conducted using more advanced pricing strategies (and such studies are quite rare), significantly higher elasticities result, reaching as high as 0.9% during some time – and price-periods. In one example, research conducted in the Swiss electricity market concluded that there is little room for discouraging residential electricity consumption using general (average) electricity price increases. This is consistent with historical findings. However, as shown by Filippini (1995), a combination of price increases and decreases, varied over a time period (a day, week or season – so-called time-of-use pricing), will yield markedly higher elasticities during critical time periods. In a further independent study Filippini went on to conclude that demand response can be an effective instrument for achieving electricity conservation and that "a widespread introduction of time-of-use pricing in the residential sector seems to be a more effective instrument to achieve efficient utilisation of existing production capacity than a general increase of the electricity price index"[7].

Demand Response – System Led

Demand response has a valuable role to play when incorporated into market design as a system resource. In markets that operate with a centralised dispatch, the systems and processes implemented by the market operator can normally be re-designed quite easily to incorporate the functionality needed to enable demand response. Indeed, this may be an important pathway for developing cost-effective demand response programs.

System-led demand response is generally reactionary and operates in the event that the market buyer of demand response services – normally the Independent System Operator – is required to react to a market condition in order to maintain system operation and reliability. The response, in the form of a price signal, is offered to all participating and eligible loads in return for pre-agreed load changes.

Since the maintenance of system operation and security of supply in liberalised markets are regulated by performance standards, system-led demand response is often provided with regulatory oversight, and may include a non market based subsidy[8].

Direct Load Control and Curtailment

Direct control programs are implemented by system operators and are triggered in response to volatility in wholesale pricing, or system and network constraints. Direct control differs from load-shifting in that the

7. Independent Research Study – Swiss Residential Demand for Electricity (Elektrizitätsnachfrage der schweizerischen Haushalte) – Massimo Filippini (2000).

8. Non market based subsidies are financial incentives provided to stimulate participation and to offset the effects of any net revenue loss incurred by utilities operation demand reduction programmes – examples include the Day Ahead Economic programs operated by US Independent System Operators.

timing of reductions is governed by the system operator, with little or no obligation to request real-time compliance from the consumer.

This approach necessitates pre-agreed programs with consumers, which establish commercial terms for participation. Program design for the residential sector will focus on reducing load through equipment cycling. Heating and cooling systems will be switched and cycled on a rhythm agreed in advance.

Such customers require controls to be installed on interruptible equipment, such as electric heating load, air conditioners or swimming pool pumps. In the residential environment these types of programs are automated and remotely controlled through the use of radio, ripple control, mains control or tele-switch devices. These control technologies are installed directly to end-use devices or through other controls such as buildings energy management systems or thermostats.

In the industrial sector, target customers tend to be larger industrial operations that can reduce some of their load to a minimum threshold. Contracts are agreed in advance for quantities and durations of dispatched load reduction. Direct load control programs in the industrial sector are often customised to the particular industrial application and may include lighting, heating, air-conditioning, manufacturing or production process restrictions. Load control of the participating customer can be facilitated either by remote control devices or, for larger customers, by direct intervention of a facilities or operations manager.

In both segments commercial terms are established in advance and are based on:

- Number of control events or cycle rate;
- Quantity of load reduction;
- Period of reduction;
- Seasonal, week and hour of day restrictions.

Payments for participation are based upon all of these factors. Settlement is accomplished through bill credits for residential consumers or, for industrial customers, measured reductions from a pre-state validated consumption baseline.

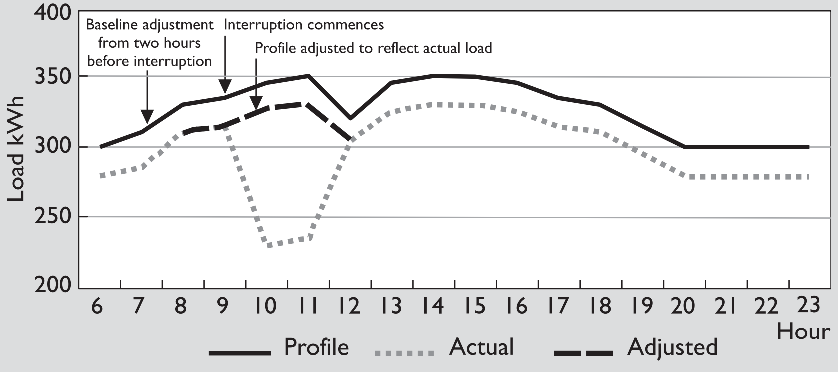
CASE STUDY

Interruptible / Direct Load Control Illustration

In the United States market, New England Pool (NEPOOL) participants are invited to enter into agreements with large customers, regardless of who the customer's current supplier is. Customers are equipped with an internet-based communications system which enables them to monitor the price of electricity. Customers are compensated for their load reduction by the enrolling NEPOOL participant. In addition to customer and participant contract gains, NEPOOL is able to reduce its on-line unit capacity commitment, and so produce further cost saving.

Customers are required to have a minimum interruptible load of 100 kW up to a maximum of 5 MW (greater load reductions are possible at the discretion of NEPOOL) and must be willing and capable of interrupting within 30 minutes of receiving a NEPOOL initiated instruction. Load reductions will be called following a contingency loss, or after accounting for voltage reduction as 10-minute reserve capacity deficiency and such interruptions will normally not exceed 2 hours. Agreements are set with a minimum interruption amount and must be available for interruption between 07.00 hrs and 19.00 hrs weekdays, excluding holidays.

Measurement of load reduction is achieved using a baseline historical profile against actual consumption. The baseline is calculated using the last 10 normalised business days, taking a simple average for each hour. Baseline is adjusted to actual usage for the two hours preceding the interruption.



Enrolling participants receive a daily compensation for availability based on Thirty-Minute Operating Reserve (TMOR) Clearing Prices. Payments will be for each interruptible load and are an amount equal to the TMOR Clearing Price times the amount of interruptible load that was assigned to the participant and which was available for contingency coverage. Penalties are applied for non-performance and include forfeiture of payments back to the beginning of the month.

Interruptible Loads

Whilst not functionally different from Direct Control programs, this term is used to refer to large industrial users who can shed larger portions of load. So-called interruptible contracts will be placed by companies who operate industrial processes which are flexible in terms of time of operation (not necessarily duration). Typical examples include water companies' irrigation programs, chemical production facilities and large furnace or boiler processes.

Emergency Programs

Emergency Demand Response Programs (EDRPs) have been developed, typically as one of a portfolio of measures designed to deal with declared emergencies, during which the continued controlled operation of the network is at risk and brownouts and/or blackouts are likely. The trigger for the emergency "event" will be defined by network reliability and security standards, published in advance by the system operator.

Participants will typically be notified 24 hours in advance of any expected emergency event, with confirmation provided nearer to real-time through notification by telephone, fax or email. Table 2 below provides some examples of programs in operation in the United States and Canada.

Table 2

Current Emergency Load Response Programs

Company	Program	Minimum Size	Price Incentive	Financial Penalty
Independent Market Operator (Ontario)	Emergency Demand Response Program	N/A	Cost reflective real-time rate	None
US State Utilities	Optional Binding Mandatory Curtailment Program	15% reduction on entire circuit, in 5% increments	Exemption from rotating outages	$6,000 MWh of excess energy
PJM	Emergency Load Response Program	100 kW	Higher of $500 MWh or Zonal LMP	None
California Independent System Operator	Demand Relief Program	1 MW Load reduction	USD20,000/MW – month and $500/MWh	Performance Based Capacity Payment
San Diego Gas & Electric	Rolling Blackout Reduction Program	15% reduction from maximum demand, at least 100 kW	$200/MWh	None
New York Independent System Operator	Emergency Demand Response Programs	100 kW reduction per zone (aggregated)	Greater of real-time price or $500/MWh	None

Demand Side Bidding

Demand Side Bidding (DSB) is a term which refers to the opportunity offered by some electricity trading markets for consumers to choose when and how to participate in real-time and day ahead spot markets. The process allows the consumer to be paid a market price for withdrawing load, when required by the market operator, in a similar way that generators are paid to supply.

Consumers will bid in a specified reduction, duration and availability, after which bids will be ranked and chosen according to the market requirement. All bidders are typically paid the highest accepted bid offer or, in the case of certain developing DSB markets, a minimum capped rate.

DSB markets have been introduced to support many aspects of maintaining an efficient and reliable electricity market, and can typically include:

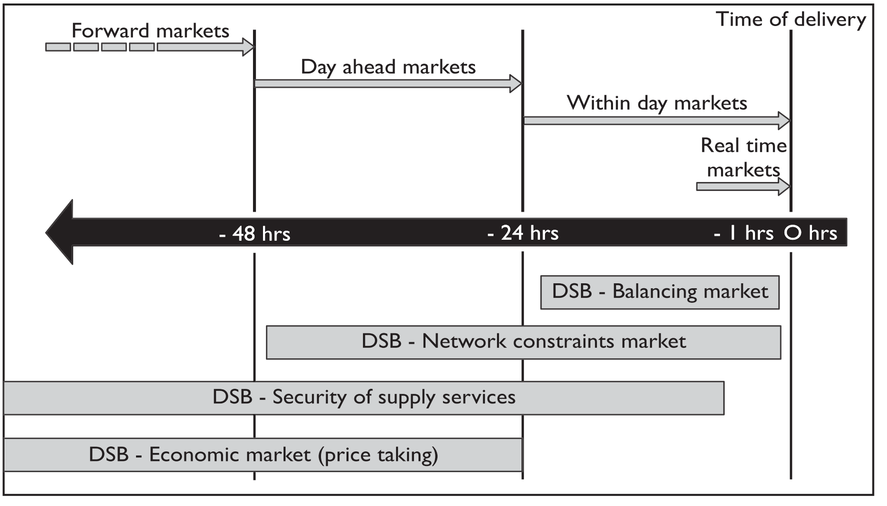
- **Network constraint services.** Congestion relief markets where the market prices are segmented to reflect the locational value of the bid requirement.
- **Security of supply / ancillary services.** These markets can feature short or long term reserve requirements.
- **Balancing markets.** These markets may provide short run reserve margin capability and/or network relief, where the term balancing is used to imply a near real time role, hence balancing markets typically operate on day-ahead markets.
- **Economic markets[9] (price taking).** Economic markets are those which enable consumers to express their valuation of energy price based upon current market clearing prices. This transfer may occur at times when the market is unconstrained, but where the consumers valuation is simply below the prevailing clearing price.

9. To the extent that the economic DSB markets are optional in presenting consumers to access market prices, these products can be considered to be Market Led demand responses. In principle DSB enables Market Led responses; in practice DSB is used by system operators to procure controllable system resources using the bidding process as an open and transparent market mechanism.

Different markets call for different planning horizons and response times. Reflecting this, operators will assign a service requirement to a bid window, as defined in Figure 1 below.

Figure 1

DSB Bidding Markets



From an economic point of view, consumers should be willing to reduce their electricity consumption if the value to them of an extra unit of electricity is less than the market clearing price. In wholesale markets this clearing price is set by the most expensive unit that is called to match demand in a given time period (often each half hour). Absent demand side bidding mechanisms, this price will be set solely by supply resources, which at times of peak demand will consist of high-cost peaking generation plant. In DSB markets, load-reductions by consumers will ensure that high-cost peaking plant is not dispatched, where the cost of the peak supply is beyond the customer's willingness to pay. As a result, additional resources are available to a constrained market and prices are formed more efficiently, accounting for the economic considerations of both suppliers and consumers.

There are two key requirements for enabling consumer access to DSB markets: first they must have a controllable load. This may be a process or activity which can be reduced, and may be facilitated through the use of a local control technology, such as a Building Energy Management System (BEMS). Second, the bidding process requires that consumers are able to access up-to-date information on market prices and have a means of submitting their bid. On the consumer side this will typically require some investment in information technology, or in some cases it is achieved by systems provided by the market operator.

DSB markets are in place in most member countries' wholesale spot markets, although in most cases they are used only by large industrial companies who are able to provide high-volume trades or specific network or balancing services on short notice periods.

Demand Response – Market Led

Market-led demand response is generally a bilateral agreement between a customer and a retailer, undertaken for mutual financial benefit. In the normal course of events, retailers contract with customers to provide power at a certain retail price, and then arrange to buy energy and ancillary services on the wholesale market to fulfill those contracts. Retailers face one dominant theme in deciding how to price their products to various customer types – how to manage the financial risk associated with uncertainty about future customer loads and wholesale power prices. That is, looking at a future time period, retailers do not know exactly how much electricity each of their customers will consume, nor what the wholesale prices for that power will be at the time they will have to supply it.

In fact, retailers face two sources of risk when they offer guaranteed prices – wholesale price variability and load variability. First, they do not know what wholesale prices will be in the future, when they will have to purchase the power needed to meet their customers' demands. Second, they do not know how much their customers will consume in any given time period in the future, since many loads will be sensitive to factors such as weather and customers generally are not required to notify retailers when they add new loads. Therefore they cannot enter forward contracts and be sure to meet all of their customers' demands; they will generally have to purchase or sell back some power in spot markets.

Two particular types of price structures illustrate opposite extremes of the range of possible products that retailers may offer to consumers[10]. At one extreme is a guaranteed flat price per unit of consumption, such as a constant price in every hour of the period of the contract. In this case, customers may consume power whenever they wish at the guaranteed price. Under this arrangement, the energy supplier faces the entire wholesale price risk, and will need to include a risk premium in the price offered. Viewed alternatively from the customer perspective, this premium reflects the cost of insurance against volatile power prices.

At the other extreme are spot prices, in which the supplier offers to provide whatever amounts of electricity the customer wishes to consume at an hourly price that is tied directly to the wholesale price of power. This type of arrangement eliminates all risk to the supplier, who will be able to offer the product at little or no mark-up, needing only to cover their operating costs. The customer, however, bears all of the risk associated with uncertain wholesale prices. This is an option generally only available to larger consumers in a number of power markets.

Between the two extremes, of spot pricing and a single guaranteed price in all hours, there is a wide range of possible price structures that have the effect of changing the allocation of risk associated with the factors described above.

Two common intermediate price structures are guaranteed prices which are known in advance but which may differ in certain time periods (e.g., flat, seasonal and time-of-use (TOU) pricing); and variable, or dynamic, prices that change on an hourly basis during at least some time periods to match changes in wholesale prices (e.g., real-time pricing and "critical" peak pricing). The guaranteed price structures will include a risk premium, as described above; dynamic pricing may not. These pricing categories, which may be used to increase consumer response, are discussed in more detail below.

10. A more extreme form of pricing exists in the form of guaranteed quantity and price offers. Under these conditions the consumer is guaranteed a fixed price for the term of the contract, irrespective of either quantity or time-of-use. The products, although uncommon, are used by consumer's who are willing to pay a premium to avoid the risk of any form of price exposure.

Time-of-use (TOU) Pricing

Traditional time-of-use programs, which vary the price according to the hour, day or season of consumption, have long been used by utilities as a tool for balancing demand. A significant body of empirical evidence has been compiled by economists on the market value of the utilisation of time-of-use products, demonstrating that they can provide significant economic efficiency gains to both the consumer and the supplier, but which remain as yet, largely unrealised[11].

Some retailers have recognised the potential to increase their control over the time at which their customers use energy. In the United States, Pacific Gas & Electric (PG&E) has been a leading proponent of residential time-of-use rates since their first voluntary residential time-of-use program was introduced in 1982. Since then, the number of participants has grown to over 86,000 residential customers. As of the early 1990's, 80% of these customers saved $240 per year by participating in the program, while PG&E recognised benefits from the resulting demand shift to the off-peak periods.

Time-of-use pricing requires that both the supplier, or retailer, and the consumer determine a "value" for the electricity supplied during a specific hour of the day, day of the week or season. This process gives rise to pricing models which incorporate so-called peak price rates, economy or off-peak price rates, along with any number of intermediate prices.

In the context of the newly-formed liberalised electricity markets, capturing the benefits of pricing has proven to be elusive. Unlike real-time pricing (discussed below), time-of-use prices are set in advance and are fixed for a period, quite often subject to annual review. In liberalised markets where prices can vary dramatically in real-time, this has the effect of requiring that time-of-use prices offered to the market are buffered, or insured from the actual price performance of the wholesale market, thereby limiting the retailer's exposure to significant wholesale price variations. To balance this risk when setting time-of-use pricing levels, and faced with the potential of volatile wholesale market price, suppliers need to bring to bear their knowledge both of the forward electricity price curve and of their customers' price sensitivities.

11. The Economics of Real Time Pricing / Chris King AEI June 2001.

Time-of-use pricing products provide retailers with an effective way to use price to control demand, and therefore to manage risk. There are also additional benefits to be accrued in respect to customer amenity. A 1992 study conducted by the Electric Association in the U.K. showed the majority of customers favoured a time-of-use rate tariff and that they adjusted their use of electricity. As expected, usage was reallocated to the less expensive off-peak periods, while overall monthly consumption remained relatively constant.

Real-time Pricing (RTP)

Real-time-pricing is a more advanced form of pricing designed to increase the transparency between wholesale and retail markets. The basic principle is that the end-user price is linked, either directly or indirectly (hedged), to the wholesale market clearing price. Also known as dynamic pricing, these products refer to any electricity tariff where the timing and prices are not known or set in advance.

Real-time-pricing products offer a range of options to rebalance the risk and reward between the supplier and the consumer through a combination of fixed prices, market prices and forward contract options. The level of risk assumed by either party can be pre-determined through the development of highly time sensitive prices for fast-response markets, such as hour-ahead, and fixed time period prices for slow-response markets, such as domestic retail. A fast-response market product combining both day-ahead and hour-ahead participants is illustrated in the Georgia Power case study shown overleaf. Analysis of this program reveals that customers' load response to changing prices under real-time-pricing is significant and consistent, and that load response is consistently larger at higher prices[12]. Further economic analysis of this type of product indicates that dynamic real-time-pricing provides far greater economic benefits than traditional time-of-use pricing[13].

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12. RTP Customer Demand Response – Empirical Evidence on How Much You Can Expect – Steven Braithwait and Michael O'Sheasy, Christensen Associates (June 2001).

13. Douglas Caves and Kelly Eakin of Christensen Associates, and Ahmad Faruqui, of EPRI – Study found that if 5% of retail load, having a demand elasticity of only 0.1, faced spot prices, super peak prices can be reduced by almost 40%. If 10% of load faced spot prices and had a demand elasticity of 0.2, super peak prices could be reduced by over 73%.

Critical-peak-pricing (CPP) is a hybrid of real-time-pricing and time-of-use; a typical design will feature a traditional time-of-use rate in effect all year except for a contracted number of peak days, the timing of which is unknown, where a much higher price is in effect. The number of these critical peak days is known in advance, but the price and timing of them is not. Critical price days are signalled to consumers with some advance notice, typically the day before the event, using automated communications.

In France, Electricité de France (EDF) has what is currently the world's largest critical-peak-pricing program in operation (10 million customers). Under the terms of the *Tempo* program, simple intuitive "signals" (red, white and blue days) are used to communicate critical-peak-pricing days. Experience of these programs indicates that doubling the on-peak price leads to peak-load reductions of up to 20%. The price elasticity has generally been measured at 30% (a 15% price increase yields a 5% reduction in consumption).

A less complex form of critical-peak-pricing is so-called Extreme Day Pricing (EDP). Extreme day pricing follows the form of critical-peak-pricing, but may only feature two prices: e.g for ten days a year, the timing of which is unknown in advance, a high price is in effect for all 24 hours of the day. For the remaining 355 days, a single low price is in effect all 24 hours.

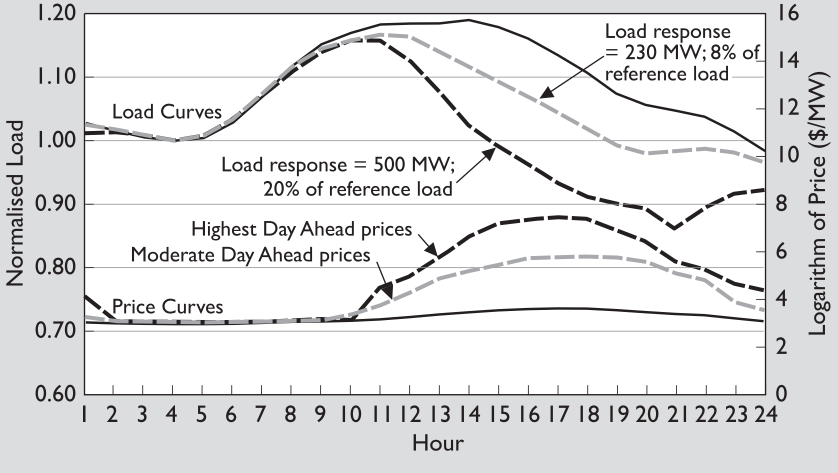
CASE STUDY

Economic Real-time Pricing

Georgia Power

Georgia Power Company (GPC) has in excess of 10 years experience in the development and delivery of its real-time pricing product. The product tariff comprises of two key parts. A standard tariff product is used for the Customer Base Line (CBL), which is based upon the customers' typical historical usage pattern, and a real-time price component which is paid for any deviation from the CBL.

Customers who respond to real-time prices with load reductions are credited with market prices for the quantity of reduction, as measured from the CBL. The use of the standard tariff for the CBL component of consumption enables customers who do not respond to price signals, and who maintain their historical CBL profile, to be effectively hedged against market price volatility.



CASE STUDY

A further innovation of the program enables customers who increase consumption beyond their baseline, and who are thus exposed to real-time prices, to contract with Georgia Power for "price protection" products. Such products enable customers to purchase forward contracts for additions to their CBL.

The program currently has over 1,700 Commercial & Industrial participants representing over 5,000 MW of contracted peak demand. The illustration page 34 demonstrates customer response from reference load during periods of both high and moderate pricing.

Load response has been measured as high as 20% of contracted demand, or 1,000 MW, at prices ranging from $0.50-$2.00/kWh.

This real-time-pricing program provides Georgia Power real-time access to load reduction and thus positions the demand side as an alternative resource to supply side options, such as peaking plant and wholesale power markets, during times of high prices and resource constraint. GPC routinely analyses its customers' price responsiveness, and incorporates this information into load response models that are used in both daily dispatch operations and long-term system planning.

Program participants are provided with a risk balanced portfolio of pricing services, enabling them to effectively sell back usage to the market when it is economically efficient to do so, whilst providing market priced incentives and insurance products to manage risk of non-performance.

DEMAND RESPONSE MARKETS AND ECONOMICS

The liberalisation of electricity markets has created competition in the generation and retailing of electricity and separated network functions into transmission and distribution. In such a system, there can be many beneficiaries of a customer's decision to provide price response. The key question remains how to quantify the benefits of demand response that are not currently captured in wholesale prices (e.g. avoided network congestion, lower price volatility and risk) and ensure the economic gains are distributed efficiently and equitably amongst market participants.

Market / Industry Structural Impacts

■ Demand Response – Pre-market Reform

In traditional regulated, vertically-integrated markets, demand response was regarded as load management: a tool for utilities to reduce investment in peak generating capacity, through the use of peak demand charges and time-of-use tariffs, or through direct investment in demand reduction on the customer's side of the meter (e.g. subsidising or providing free-of-charge energy efficient light bulbs). Vertically-integrated utilities (those owning and controlling all electricity supply-chain activities) were able to capture the value of the full range economic, efficiency and environmental benefits associated with traditional Demand Side Management (DSM) programs.

Demand side management measures were also used by vertically-integrated utilities as a means to delay network upgrades and investments in constrained networks, which they themselves owned. In addition, specific measures were implemented in the context of regulated public policy efficiency objectives, often supported by a subsidy, and used as a regulated performance measure.

The majority of demand side management programs were aimed at large industrial consumers for whom electricity was an important component of cost and who could more readily turn off a load in response to the request of a utility. However, the 1980s and 1990s also saw a number of utilities with programmes to shift load among residential consumers by, for example, remotely controlling the operation of residential water heaters or air conditioning loads.

■ Demand Response – Post-market Reform

The liberalisation of electricity markets has fundamentally and dramatically altered the business case for investment in demand response: new and distinct companies emerge, each with different incentives and interests – generation and retail supply are now competitive businesses that are separate from the monopoly networks. As a consequence of post-reform market structures, the incentives to undertake demand response have been dispersed amongst these various parties:

■ Consumers may lack incentives to respond or behave efficiently – initial phases of retail competition offer simple price discounting to attract consumers;

■ Generators have little interest in demand response (except as a hedge to unplanned outages) and have dominant relationships with system operators (who effectively become responsible for real-time system balance), while peaking generators view demand response as direct competition;

■ System operators now seek demand response as a means to balance supply and demand economically and to keep the system reliable;

■ Network operators may look to demand response to relieve network congestion and hence improve local reliability/quality of supply, but incentives to do so may depend crucially on the treatment of demand response expenditures under rate-of-return formulae;

■ Retailers can be interested in demand response as a means to balance more economically the demands of their consumers with the supplies they have contracted.

In any given market situation, these different players will value a unit of demand response differently according to its purpose, as illustrated in the post-reform markets shown in Table 3 page 39. Furthermore, it is ultimately consumers that make the decision whether or not to reduce their consumption of electricity at a particular moment in time. For the market to make efficient decisions all other participants who stand to gain from demand response have to signal to the consumers the value they place on a reduction in demand. Therefore the only way to obtain an economically efficient outcome is for all of these parties to participate in some way in the price formation process. However this process, requiring exchange of value and price information between multiple parties, will call for significant investment in intra-party communications, metering systems and information technology which has thus far prevented multiple party interests to be consolidated.

Table 3

Markets and Demand Side Participation – Pre and Post-Reform

Markets	Pre-Reform Markets Demand Side Management	Post-Reform Markets Demand Response
Retail	Traditional TOU as a resource for Vertically Integrated Utilities	Pricing innovation, increased customer choice, price determination
Wholesale market	N/A	Economic dispatch, additional market resource & increased flexibility
Security markets	N/A	Ancillary markets – Capacity and reserve markets
Network reliability	Demand charges used as planning resource	Distributed transmission and distribution network relief, capacity planning
Efficiency & environment	Regulated energy efficiency programs	Offsetting peaking plant and conservation, efficiency and environment markets
Market power mitigation	N/A	Additional market resource – counterbalance to supply

This dispersal of value, and hence of market incentives, for demand response represents a clear market failure in liberalised electricity markets, and a source of economic inefficiency[14]. The counterpart of allowing the "invisible hand" of competition to regulate exchange is that the regulatory regime internalises all significant external values associated with electricity supply and use into the marketplace. This may require a willingness on the part of governments and regulators to intervene in order to ensure that demand response is integrated into the efficient operation of liberalised electricity markets.

Potential remedies to this market failure may involve revised market designs that provide a mechanism to aggregate the now-dispersed demand response values, thus enabling a private business case to be constructed for the necessary investment in demand response infrastructure. Alternatively, it may involve institutional investments and remedial policy interventions. As we will discover in Chapter 4, there are relatively low levels of demand side participation in evidence in IEA member countries' markets today. This suggests that disconnected markets, where the demand side fails to respond to tight supply side conditions[15] and high price episodes, have already developed and that business models have not emerged to provide a natural market remedy. Thus it may be an early signal that remedial policy intervention is in fact required.

An additional benefit of intervention to facilitate the growth of demand response in electricity pricing is that when markets can form efficient prices and demand-supply balances, the need for longer-term price regulation may be significantly reduced.

The benefits of enabling demand response within these new markets are significant. In a recent study[16] it has been estimated that incorporating demand response into the United States market, with dynamic pricing, could lead to savings of between $10 billion to $15 billion per year. This estimate assumes dynamic pricing would be applied to all types of

14. See, for example, C.A. Tisdell, ***Microeconomics of Markets****, John Wiley & Sons, 1982, p.70.*

15. "Without the ability of end-use electricity consumers to respond to prices, there is virtually no limit on the price that suppliers can fetch in shortage conditions" William Massey, FERC Commissioner, August 2000.

16. White Paper – The Benefits Of Demand-Side Management And Dynamic Pricing Programs – Mckinsey & Company – May, 2001 customers, including residential, commercial and industrial facilities, and that users, on average, would shift five to eight percent of their load from peak periods and curtail use another four to seven percent. About 20% of the savings are attributed to such changes in usage, with the balance of 80% of the savings attributed to lower wholesale peak prices.

McKinsey translates the savings into several other measures of benefits, including avoiding:

- $16 billion in peaking plants (250 peaking plants at 125 MW each, or 31,000 MW of peaking capacity); and
- 680 billion cubic feet of natural gas per year; and
- 31,000 tons of nitrous oxide pollution per year.

The consumer's interest in demand response markets is discussed in detail below.

Emerging Demand Response Markets

Retail Markets

As discussed in Chapter 2, it remains a widely-held conviction that retail demand for electricity is fundamentally price inelastic[17]. This belief may be further reinforced by the fact that wholesale price movements are not currently moderated by demand side responses, and are driven almost exclusively by supply side constraints. However, virtually all studies of price-variant retail products have consistently demonstrated that demand can be elastic. This hypothesis can be further illustrated by referral to another capacity-constrained market: telecommunications. Retail pricing in telecommunication markets, post-liberalisation, has been quick to reflect capacity constraints in bandwidth or network access in pricing structures. Highly-innovative products have emerged catering to all forms of lifestyle: large users, smaller users and time-dependent users. This has enabled a highly cost-reflective infrastructure, ensuring efficient allocation of investment and infrastructure resources. Pricing in telephony markets is a key instrument in modulating demand and for planning future capacity needs.

17. Ibid., p 10.

In contrast, consumers in retail electricity markets in most cases pay a price which is time-invariant and does not efficiently reflect the cost of capacity or the marginal cost of supply. This may in part be attributed to traditional government and industry perceptions concerning consumers' willingness to be exposed to any form of time-variant pricing. However, today's consumers are already in effect paying for variability in their cost of supply and any latent inefficiencies present in the supply chain, in the form of an insurance premium (Hirst 2002).

It has been observed that most consumers may not want to face volatile prices because they equate volatility with higher bills[18]. This highlights a problem of the difference between consumers' perception and the contrary evidence of economic studies, attributable to an "information gap". The gap exists because consumers have no concept of the insurance premium they are currently paying, and why they are paying it. Specifically, consumers are not aware of the effects on this premium of high prices during a few hours per year, or the longer-term effects on price of reducing or shifting loads.

Similarly, consumers may not be aware that under a demand response regime, the high prices they may be exposed to during a few hours a year will be more than offset by low prices during much of the year, resulting in a lower electricity bill for the year as a whole. In addition, consumers may not be aware of the opportunities they have to shift consumption from high-priced to low-priced periods, further reducing their electricity bills.

The retailer is perhaps the obvious agent to work with the consumer to offer this information along with the demand response pricing option, as well as to make the necessary investments to manage and shift their electricity load. However, some key problems immediately emerge. First, retailers may not be able to access a financial return from the impacts of the demand response program on the wider market (e.g. avoided network congestion, lower price volatility and risk). Second, the retailers themselves, many with few physical assets of their own, may not be willing or able to finance significant investments in the equipment needed to

18. Faruqui, Hughes, and Mauldin (2002).

ensure consumers can manage their demand in response to prices. Finally, interest in demand response is likely to be low in any market with significant over-capacity and low energy prices.

It is therefore not surprising that retail participants in liberalised markets have, in most cases, seen little price innovation beyond pure discounting[19]. In a recent United Kingdom survey, commissioned by OFGEM, "reduced cost" was stated as the primary reason for switching by over 70% of respondents; this in a market characterised by fixed-rate products. This re-states what retail paradigms are ready to acknowledge – that price is driving consumer choice.

Telecommunications tariffs have been quick to attempt to align consumer preferences within supply-side cost drivers, through the use of so-called "lifestyle tariffs". Lifestyle products reflect deeper retail knowledge of the behaviours' of consumers, according to known attributes of their respective lifestyles. There has been virtually no growth in such advanced pricing within electricity markets. An individual consumer in a small gas-heated residence will often be supplied on the same tariff as a consumer in a multiple-occupancy electrically-heated residence. Lifestyle, time-variable product opportunities exist today for targetable consumer segments:

- Single-occupancy residence.
- Multiple-occupancy residence.
- Weekly commuters (Monday to Friday or Saturday to Sunday occupancy).
- Holiday homes (seasonal occupancy).
- Retired consumers (Stay-at-home or travelling).

Wholesale Markets

An important feature of liberalised electricity markets is that they allow wholesale prices to be set freely by market participants. Most electricity is bought and sold under contracts between consumers of electricity and

19. In the UK, OFGEM estimates that this discounting has "saved" consumers in excess of £1billion per year.

retailers, who in turn have contracts with producers of electricity. Since the amount of electricity demanded (and the availability of supplies) in real-time is uncertain, a spot market plays an important role in balancing supply and demand.

Prices are normally set in the spot, or wholesale, market by a combination of price/quantity bids for the supply of electricity based on forecasts of expected demand for electricity (eg, one day or one hour ahead). For any given level of demand in a settlement period (say, each half hour) prices are set for all suppliers by the "marginal bidder" that is actually called upon to supply in that half hour (the "clearing price"). End-users of electricity (apart from very large "market customers" who can buy direct from the market) only enter the price-setting process insofar as they shape expectations of future demand, and demand is assumed to be inelastic.

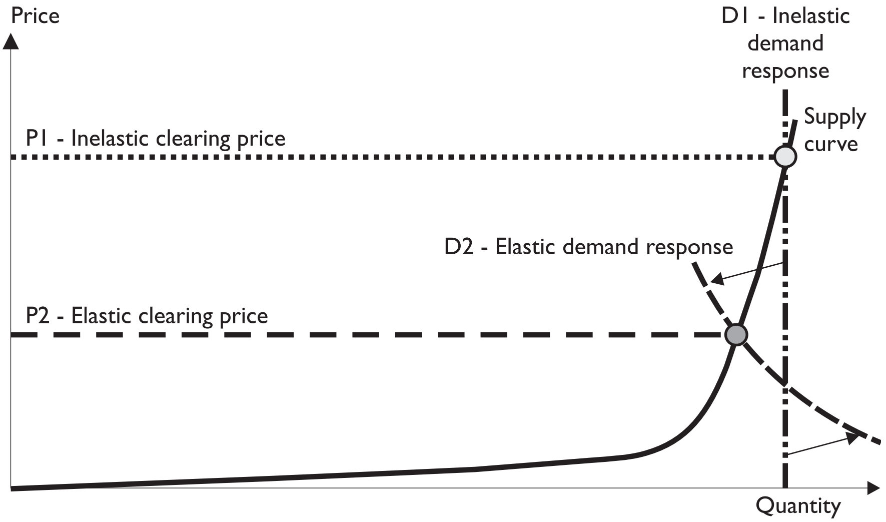
In an ideal competitive market, by contrast, prices are determined by how much consumers value demand for electricity and how much it costs to supply. When capacity is not scarce, the price can fall to the marginal cost of supply, which may be far lower than the value all consumers place on electricity. Thus in markets where there exists a large surplus of generating capacity, one should expect relatively little demand response – the electricity price is too low to make any response cost-effective. When capacity is scarce, and in the absence of exposure to real-time price information, end-users may continue to demand electricity even when the price exceeds that which they would be willing to pay.

However, the delivery of retail demand response that reflects wholesale market conditions has several important economic impacts which should be considered. The effect of increased demand response on real-time wholesale price is illustrated in Figure 2.

In the case where demand is inelastic (D1), extreme wholesale prices (P1) will be experienced as increasing demand approaches capacity. The inelastic behaviour of consumption is accounted for by the fact that despite such marked price rises which prevail at this end of the market, these prices are rarely signalled to the actual consumers. However, the second demand curve (D2) demonstrates the significant effect of a modest consumer response (in the case of the order of 5%) on real-time wholesale prices (P2). The addition of this demand response capability to the wholesale price formation process acts as a natural price-capping mechanism, enabling markets to clear at lower market prices. Over the long term, this will yield lower average retail prices for consumers.

Figure 2

Impacts of Demand Elasticity on Wholesale Price



This model has been well illustrated in recent electricity market research. A simulation constructed for the United States market showed that having about 10% of retail load on a real-time price would have mitigated the United States Midwest price spikes of 1998 and 1999 by about 60%[20]. A similar study in the California market showed that if about 50% of the large industrial load and 25% of the large commercial customer load were on real-time pricing, a typical wholesale price spike in the range of $750/MWh would produce a load reduction of 2.5%, which would in turn cause a reduction in wholesale prices of 24%[21].

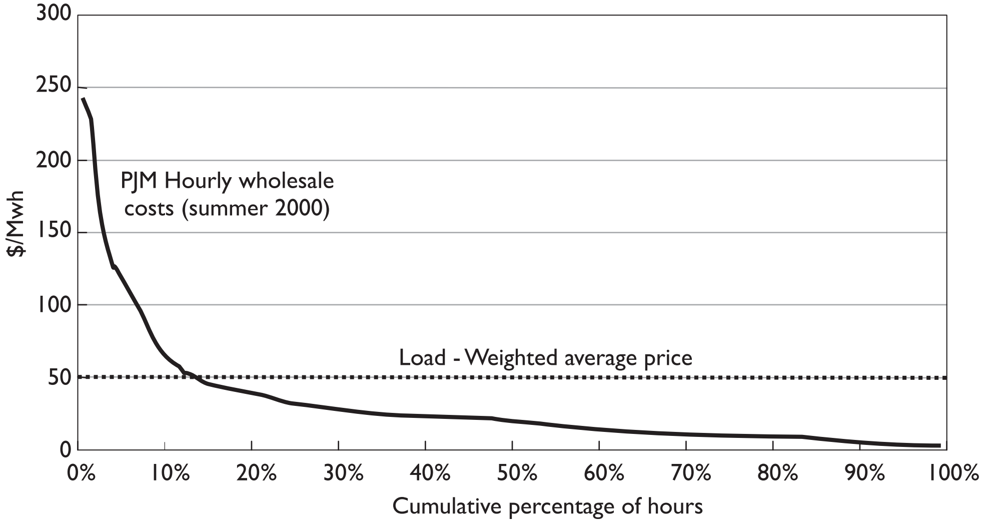
20. D. Caves, K. Eakin and A. Faruqui, "Mitigating Price Spikes in Wholesale Markets through Market-Based Pricing in Retail Markets," The Electricity Journal, April 2000.

21. S. D. Braithwait, and Ahmad Faruqui, "Demand Response – The Ignored Solution to California's Energy Crisis", Public Utility Fortnightly, March 15, 2001.

Furthermore extreme prices, which have been seen to be present in capacity-constrained wholesale markets, whilst having a marked effect on retail prices, are only experienced for relatively short periods, as illustrated in Figure 3 below. In New England, the top 1% of the trading hours, account for a total of 15.8% of the total wholesale market costs (weighted by load).

Figure 3

PJM Wholesale Price Distribution Curve



Increased demand response in wholesale electricity markets can reduce wholesale electricity prices that benefit all customers. In the short-term the impact of lower prices will be to encourage power producers to delay investments in new peak production. Similarly, the volatility of electricity prices will be reduced. The disincentives for investment in peak generation, that increased demand response would give, make it important that the focus be increasing demand response in an economically efficient way[22] – ensuring that investments in either demand or supply side investments are evaluated as equitably as possible.

22. *See L.E. Ruff (2002).*

Over the medium to long-term, stronger elasticity will mean that price peaks will be less dramatic but somewhat higher prices will persist over a longer number of hours, providing the basis for a return on the necessary investment in demand response capability[23].

Thus the main long-term economic impacts are primarily a flatter price curve with less volatility, but secondarily somewhat lower wholesale prices. Prices will also be more predictable and easier to contract, and thus risks should be reduced for all market participants helping the market to function more effectively.

As described in Chapter 4, the market's evolution to access these benefits has begun, although it is far from being complete. The benefits of demand-based price response on wholesale market price will emerge through two distinct market channels:

- **Direct system operator markets.** Existing system operators already offer opportunities for direct participation in wholesale markets. A variety of demand-side bidding, interruptible load and emergency contracts are in operation in United States, United Kingdom, Scandinavian and Australian markets. However, participation is typically very low and in most cases is not of sufficient scale to have notable impact of wholesale price setting.

- **Indirect system operator markets.** Indirect markets are those served through intermediaries, such as retailers or aggregators, who buy the bulk of supply on wholesale markets. Such intermediaries typically interact with wholesale markets by bidding in blocks of demand, the price being set according to the highest supply side bid price required to match demand. Absent demand elasticity in the bid demand blocks, wholesale prices will naturally peak in line with capacity and network constraints and be further impacted by any residual supply side market power. Increased use of time-variable pricing (increased demand elasticity) by retailers and aggregators would enable more flexible demand bidding, lower wholesale prices and lower long-term supply prices to consumers.

23. *See L.E. Ruff (2002), p. 4.*

■ Reliability Markets

Recent reliability problems in North America, the UK, Sweden and Denmark have once again focused political and business attention on the value of reliable electricity supply. While demand response cannot be relied upon to deal with extreme events, such as the loss of supply to some 50 million customers in the US and Canada on August 14 2003 and a futher 58 million in the Italian blackout on September 28 2003, it could make a significant contribution both to forestalling the incidence of congestion-related failures and also to the timely recovery from major disruptions.

To maintain reliability, the system operator must continuously balance generation and demand, maintain acceptable voltages throughout the system, and avoid overloading transmission lines and transformers. As demand rises, system operators will access reliability markets to ensure that the security of network operations is maintained. In the event that demand exceeds the capacity of these reliability markets, some other form of rationing electricity must be used (e.g. rotating power cuts) to avoid a complete blackout of the system.

Reliability markets tend to operate at higher economic value thresholds, since they are accessed when network security is under threat, as demand approaches supply (as illustrated in Figure 2).This is reflecting the fact that these markets are typically supplied by expensive supply side resources, such as a stand-by peaking plant. In such cases, direct demand reductions by consumers may be able to obviate the need to call on these more expensive short-run supply side resources.

Reliability markets attract a high economic premium for participation due to the potential economic damage caused by such supply interruptions and/or inadequate power quality. A recent EPRI study conservatively estimated that such outages already cause economic losses of more than $100 billion in United States markets.The higher prices paid for reliability resources presents a more attractive investment environment for demand resources, evidenced by the emergence of some genuine demand-side participation in existing reliability markets (see Chapter 4).

In summary, access to the additional resource of demand reduction can give a system operator many more options to manage situations of tight supply rather than being forced to reduce voltage or implement rationing. Adding generating capacity to be used strictly as reserve is very expensive. Thus, the availability of cost-effective demand reduction could have economic benefits in reducing the overall generation reserve margin required. Beyond this, demand response effectively adds depth to system reserves and thus improves the reliability of the electricity system as a whole.

Ancillary Services Markets

Ancillary service markets are operated in order to provide contingency resources to the network for use in the case of an unplanned event, such as a generator outage, transmission failure or excessive, unforecast consumer demand. From a reliability perspective, these markets help system operators to maintain short-term system security.

Markets for additional resources are generally classified and contracted according to size and speed of response. Most liberalised OECD markets operate markets for standby reserves. Typical ancillary markets would include:

- **Fast reserve (spinning and non-spinning).** Typical response times may range from 10 seconds up to 5 minutes, depending on the classification and requirement. Resources may also be required to provide a ramp or delivery-rate (i.e. 25 MW/minute) and a minimum sustainable period of operation.

- **Standing reserve.** System Operators are often required to maintain a minimum level of reserve capacity. This class of reserve is contracted against forecast demand supply balances and as such will not require such rapid start characteristics as Fast Reserve. Standing reserve resources are in effect contingency, and as such may not be called to operate.

- **Power quality (voltage/frequency response).** Fast response resources required to maintain network operation within system operator-maintained power quality standards.

The technical and commercial contracts used by system operators tend to favour supply-side resources. This should be expected for a number of reasons:

■ Contract terms and standards have been developed around generator performance;

■ Dispatch of generators is well-known and considered reliable;

■ System operators' processes are structured to deal with fewer commercial interfaces (including contracting, settlements and customer service).

Consumer participation in these service markets is generally, due to the relatively complex performance and contracting requirements, limited to small numbers of larger commercial and industrial customers, either directly or through aggregation agents. However, work has begun to address these constraints to enable greater market access to a wider cross-section of demand response-capable consumers.

Recognising the institutional barriers mentioned above and the potential contribution of demand resources, in the United States market the Federal regulator, FERC, has proposed market design rule changes to ensure greater access for the demand side[24]. In the United Kingdom market, the National Grid Company continues to consult on its procurement guidelines with a view to engaging more demand side participation. Increased access to the demand side into these markets will also have the effect of increasing competition, resulting in overall lower ancillary service prices for all market participants[25].

Capacity Markets

In a well-functioning wholesale market with well-developed demand response capability, the demand-supply interaction would ensure that the clearing price includes a component that reflects the value the consumer would be willing to pay for reliability (including a reserve requirement). Absent this connection between supply and demand, market designs have established artificial valuation methods in which two basic forms of capacity market ensure the need for reliability is met:

24. Federal Energy Regulatory Commission, "Working Paper on Standardized Transmission Service and Wholesale Electric Market Design", March 15, 2002.

25. It should be noted that a corollary effect of increased competition is the potential for lower prices for supply side resources for the provision of such ancillary services. Market and policy designers should be cognisant of this effect when considering proposed rule changes.

■ Price-based Capacity

The System Operator estimates the capacity requirement, calculates value of capacity and provides payment to providers. Payment for installed capacity may be separate from, or capitalised into, payments for energy.

■ Quantity-based Capacity (Operating Reserves, ICAP)

The System Operator estimates the capacity requirement, with the value decided by market mechanisms.

Participation in capacity-based programs by providers of demand response resources poses some challenges for the designers and administrators of capacity markets. A prerequisite for participation in traditional supply-side capacity reserve markets has been that resources bid should be "firm and reliable" The extent to which either a supply-side or a demand-side resource should be considered "firm" might be reflected in an "availability risk" component to a capacity payment, recognising that supply and demand suffer from varying degrees of technical performance risk.

During the California electricity crisis of 2000 and 2001 compliance in operation of the utility-installed capacity demand response programs was low. In the program operated by Southern California Edison only 1,200 MW out of a contracted reserve of 1,800 MW was achieved during emergency conditions.

Other market flaws have been evidenced where supply and demand resources are considered to be equivalent – in the early United Kingdom price-based capacity design, demand side bidders were bidding high into the day-ahead markets with no expectation of being called, in order to receive the then-valuable capacity payments. The role of these payments was to act as a long-term investment incentive to capital-intensive supply side infrastructure, and it was neither suited nor intended for the purpose of engaging short-term demand resources.

Markets have also experienced failures which occur in heavily constrained periods when the consumer does not relate the value of interruption with the declared value of capacity payments; that is, when regulators intervene to protect consumers from extreme price variations.

The challenge for capacity program designers is to ensure that the nature of demand-side resources is reflected in the performance and contracting terms. This is not to suggest that the demand-side should be treated differently; eligibility and payments or credits must be commensurate with the risk-weighted capabilities of demand-side resources in capacity markets. In the case of capacity markets this may require that contracts are "guaranteed"; that is, guaranteed payments for guaranteed performance.

Network Congestion

As demand concentrations and the cost and environmental impacts of network construction increase, the need to reflect the locational value of network transactions has increased significantly. The locational value is a pricing signal that indicates the value of relieving network congestion at a particular point, or node, on the grid. This price component is becoming significant as network operators use the price signal to deter use of overly constrained network nodes, and as the true costs of maintaining and operating capacity-constrained networks in newly liberalised markets are progressively internalised.

Where the locational value of a resource is captured within a wholesale market clearing price, there may be increased incentives for demand resources to participate in providing network relief. In Australia, for example, the costs of adding new capacity to a constrained network are estimated to vary widely, from around AUD 90/kVA to over AUD 300/kVA. Whilst this is a broad range, it suggests that interruptible supply options (at around AUD 53/kVA) would be viable alternatives to network augmentation[26]. The network business, EnergyAustralia, has indicated that to meet the energy needs of Berkeley Vale, a fast-growing area in the central coast with an annual load growth of 3 MVA, and defer network augmentation for two years, demand resource programs costing up to AUD 192/kVA would be viable[27].

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26. *Note: comparing demand management options with average costs is roughly equivalent to comparing these with long run marginal costs (rather than short run marginal costs). This is appropriate when generation – or network – constrained, but only to the extent there are capacity constraints (ie it is not cost-effective to do all demand management options now even where they are cheaper than the average costs of network augmentation because the requirement for new capacity is incremental – 5,400 MW of new generation and network capacity will not be needed immediately, but it might be required over the next 10 years or so).*

27. *Demand Response in a Liberalised Market: the Australian Experience – Eric Groom, Independent Pricing and Regulatory Tribunal of NSW.*

Locational load response economics will vary substantially according to market conditions, particularly where environmental and siting concerns prevail. The economics of locational load response should be considered in the context of the alternative network infrastructure investments, as the comparisons for the United States market shown in Table 4 below illustrate.

Table 4

Load Response for Congestion Relief

Resource Type per MW	Start-up Cost per GW	Est. Cost
Load Response Programs	$10-15 k	$10-15 million
New Transmission	$1 k[28]	$50 million (50 mile line)
New Generation	$300 k-500 k[29]	$300-500

However, the consumer business case for investment in demand response infrastructure (to access any locational benefits or "uplift" in pricing) can be easily undermined, because the responsibility for network upgrades remains under the direction of separate transmission companies, or system operators, responsible for network planning. This is another example of the effect of dispersal of incentives, discussed earlier in this chapter.

Demand response resources, by their nature, will be distributed around the network. It also follows that the larger commercial and industrial users are likely to be positioned on the network in locations of potential peak demand and thus be well positioned to deliver congestion relief.

Policy-makers should ensure that market designs offer locational pricing signals to the extent possible, and that demand response resources are eligible to participate in these markets on equitable terms with network providers. Programs should be designed and marketed in a manner which provides appropriate emphasis to the locational value of such demand response resources.

28. *Edison Electric Institute, Transmission Pricing for a Restructuring US Electric Industry, June 2001.*

29. *Energy Information Administration, Assumptions to the Annual Energy Outlook 2001, December 2000 (Table 43).*

Market Power Mitigation

An important economic benefit of enhancing demand response is to address generator market power in wholesale electricity markets. In a market where a single generator or a small number of generators are dominant, it is widely accepted that generators can increase market prices e.g. by withholding generating capacity from the market when supplies are tight. Generally speaking, the fewer the number of firms, and the higher the barriers to entry, the more concentrated will be the market. In the case of so-called Cournot competition[30], the average increase in prices above marginal cost is given by the following expression:

% Increase in prices above marginal costs = HHI/ε

where HHI (Hirschmann-Herfindahl Index) = sum of the squares of the market shares of each competitor and ε = price elasticity of demand. From this simple equation it can be seen that doubling the demand elasticity (ε), has the same effect as halving the supply concentration (HHI).

This simple model, which is commonly employed in modelling competition in concentrated electricity markets, suggests that market power problems can be reduced by either reducing concentration in the electricity market (e.g. by requiring divestiture of generating of dominant firms) or by increasing the elasticity of demand relative to price.

In the presence of market power, suppliers have the ability to set prices above the cost of the last unit produced. This pricing behaviour – which is illegal in many countries but may be very difficult to prove – reduces the efficiency of the market by creating a wedge between the actual costs of electricity production and its value to customers. Importantly, the suppliers' ability to raise prices above costs increases with lower demand responsiveness, since there is no "push back" against the price spike. Consequently, the profit incentive of a supplier with market power to raise prices above their costs also increases as the responsiveness of demand decreases.

30. *Cunningham, Borenstein, Younes, Ilic, Stoft et al.*

The exercise of market power results in large price spikes and increased price volatility. In times of electricity shortage without market intervention, suppliers literally have the opportunity to "name their own price", subject in some markets to a cap, or Value of Lost Load (VOLL) limit. These prices above cost can result in large wealth transfers from electricity buyers to sellers, depending upon the nature of contracts in the market. While these wealth transfers are not necessarily a source of short-run inefficiency, the equity of such activity can be debated.

Market regulators employ different approaches to the measurement of market power. In the United States the Federal Energy Regulatory Commission's (FERC) current market power tests, the Delivered Price Test, and Supply Margin Assessment (SMA) do not explicitly evaluate potential of demand responsiveness within the markets. In the United Kingdom the first order form of the Hirschmann-Herfindahl Index is used. Neither of these tests accounts for potential impact of increased demand response, and both essentially assume that market demand is unresponsive or perfectly inelastic.

This may be accounted for by the fact that in both cases the regulator responsible has little jurisdiction over retail prices. Since the effects of increased demand response can be measured, regulators should further consider the value and public cost benefits of ensuring retail markets encourage more demand response.

■ Energy Efficiency and Environmental Impacts

The term "Demand Response" is not interchangeable with the term "Energy Efficiency"[31]. The introduction of price-variable demand response does not necessarily lead to an overall reduction of electricity consumption. Conventional demand response programs are focussed on shifting load from peak to off-peak times, generating economic benefits, whereas energy efficiency programs generally seek to reduce loads, regardless of the time-of-use. For this reason, demand response has not

31. Energy efficiency has, thus, a broader sense that what is usually understood with an implicit reference to technological efficiency only: it encompasses all changes that result in decreasing the amount of energy used to produce one unit of economic activity (e.g. the energy used per unit of GDP or value added) or to meet the energy requirements for a given level of comfort. Energy efficiency is associated to economic efficiency and includes technological, behavioural and economic changes.

been considered as playing an important role in traditional energy efficiency programs.

However, this paradigm requires some further examination. Creating consumer price awareness establishes a value relationship between the price paid and the end use product[32]. The increased flow of information between a consumer and the retailer increases the consumers' awareness of when power is being used, the end use or work value of the electricity and the resultant economic value being traded. As knowledge of the consumer's capability for valuing electricity increases and pricing programs are refined, price signalling can in turn be used to encourage consumers to less wasteful use of electricity. Current estimates suggest that in addition to peak load shifting benefits derived from the introduction of time variable pricing, typical residential programs also deliver approximately 2% reduction in energy consumed.

Regulatory oversight of energy efficiency in some OECD liberalised electricity markets is supported by public funding, energy efficiency obligations and through negotiated agreements and the reduction of disincentives (Table 5). Many of these policy frameworks do not include or recognise the potential impacts of demand response measures, such as time-of-use or dynamic pricing.

However, increasing awareness of the implications for energy efficiency of the current landscape of retail pricing should provide reasons for policy designers to reconsider the case. It has been suggested, for example, that lack of innovation in pricing, combined with low market prices for electricity, has been a primary factor in the failure of markets to naturally deliver an active independent energy efficiency sector.

Furthermore, emissions reductions from peak load reduction are possible, but not guaranteed[33]. Reduction in peak load will reduce output from high fuel cost generation and replace it with a lower fuel cost generation at off-peak hours. The net emissions impact will depend on the on-peak resource that is displaced (e.g. natural gas vs oil combustion

32. The end use product supplied to a building, factory or home and converted to heat, light or motive power.

33. Although not explicitly discussed in this publication, demand side response which is supported by on-site generation requires special consideration: Highly localised environment policies and regulations may apply.

turbine unit) compared to the off-peak resource which is increased (CCGT, coal or nuclear). As environmental markets develop, for example for avoided carbon emissions, this may impact on the value of demand response as a mechanism for avoiding emissions-intensive peak-load generation.

Table 5

Electricity Energy Efficiency Policy Frameworks for EU Countries[34]

Country	Electrical Energy Efficiency		Others
	Energy Efficiency Funds	Energy Efficiency Obligations	
Belgium	✓	✓	A
Denmark	✓	✓	A, R
Finland			A
France			A
Germany			A
Ireland		✓	A
Italy		✓	R
Netherlands	✓		A
Portugal			R
United Kingdom		✓	R

A *– Negotiated agreements or other commitments for energy efficiency activities or savings argets*
R *– Reduction of disincentives or setting of incentives in ratemaking of monopoly segments*

Finally, in respect to renewable supply options, there may also be a growing need for demand response as wind power, in particular, grows as a resource in response to government policies. While wind resources offer very low marginal cost and may be automatically dispatched whenever they are producing power, the power output can be highly variable. Access to responsive demand side resources will provide a useful complement to the variability of wind supply resources, increasing localised network reliability and security.

34. Source: Wuppertal Institute et al 2000; Wuppertal Institute 2002.

■ Network Planning

The traditional planning process for network operators and planners is led by demand forecasting. Weather forecasts, historical trends, regional and demographic changes and prime economic indicators are used to forecast future demand side requirements. In the planning cycle, once the demand side requirements are projected, supply capabilities (generation) are sought to ensure that supply exceeds demand at all times. This process assumes the demand-side market to be inflexible and insensitive to the increasing cost of supply-side resources.

Changing the network planning culture to recognise the potential role of the demand-side remains a significant challenge. The characteristics of potential demand responses are very different from those of traditional supply-side solutions (generation and transmission infrastructure), as illustrated in the table p. 59.

Whilst in general these characteristics should increase the portfolio of economic solutions and options accessible to network planners, the question of reliability of demand resources remains the single greatest concern. From a planning perspective the construction and sitting of a new 250 MW peaking plant can be considered to be “firm”. Subject to timely construction and delivery, and barring disruptions to fuel availability, the planner can be assured that the resource will be capable of supporting the network and that security of supply will be maintained. By contrast the contracting of 250 MW of “firm” demand response resources can be considered more challenging, as the degree of response may in part depend upon the economic incentives created by a particular market situation. Demand response aggregators, retailers and system operators must therefore ensure that demand response programs take clear account of the network planners needs. Price-response and load-reduction programs should be designed which have guaranteed contracted and incentivised performance standards. Alternatively, differing degrees of firmness could be recognised, as required by network planners, which would flow through to the value of the different demand response options. In lieu of these programs when network planners are faced with a system constraint, the question should be asked: what is the nodal cost of a mega-volt-amperes (MVA) supply increment and demand reduction? In principle, the least-cost alternative should be chosen.

Table 6

Key Characteristics of Demand Resources in a Planning Context

	Planning Resources	
	Demand Side (DR Resources)	**Supply Side (Generation)**
Size	Small[35]	Large
Location	Distributed	Concentrated
Reliability	Low-Med	High
Flexibility	High	Low
Capital Cost	Low	High
Operating Cost	Variable	Low
Environmental	Variable	High

Pricing for Demand Response

In the words of Henry Ford, "People know the price (cost) of everything, and the value of nothing". This is almost a universal truth when applied to the consumer retail electricity market. A truly competitive electricity market would set a role for consumers at the centre of the market: that is, the market design would force retail companies to focus on what customers want, and what they are willing to pay for. A willingness to pay implies that there will be a point at which the consumer would not be willing to pay. What is this price?

If the answer is not yet well understood, it is because consumers have yet to be asked. It would not be contested that electricity used to supply an emergency ward at a local hospital would attract a significantly higher value than would supply used for a garden irrigation pump. Yet despite this value gap, which should be significant, consumers are afforded little opportunity to express their preferences. Today, both consumers may be at equal risk of losing supply during a network congestion event, or else

35. *Assuming no aggregation.*

the hospital may have to make significant investment in standby generation to manage the risk of a supply disruption. Such investments can be viewed as indicators of the economic costs of undifferentiated pricing.

In addition to the electricity itself, consumers will also place a value on the reliability of the supply. If asked, consumers are likely to want 100% reliability at all times. However, most consumers would not be aware, from their past experience, of the concept of the value of supply varying over time, along with the cost of supply. Prior to the economic reform of the electricity sector, they had no reason to think about it. However, if exposed to these costs, many consumers may in fact respond differently. Some consumers would be willing to turn off some, or part of their load, at short notice, or even no notice – if the price were right. Other consumers might prefer to pay even very high prices rather than lose supply.

Pricing options in electricity markets should be diverse enough to offer consumers the opportunity to reflect their own value thresholds. If consumers' underlying preferences were expressed in the market, then generators and suppliers, as well as customers or agents acting on their behalf, would be able to make optimal investment decisions and overall economic welfare would be maximised.

Private and Public Good Economics

Regulators will have a key role to play in ensuring demand response markets emerge as an option in the market. This is because the economic benefits of demand response will be delivered in the form of both public and private goods.

Private goods are typically traded in markets where buyers and sellers meet through the price mechanism. If they agree on a price, the ownership or use of the good (or service) can be transferred. Thus private goods tend to be excludable; they have clearly identified owners and they exhibit "rivalry" (ie, there are a large number of substitutable options available in the market).

Public goods have just the opposite qualities. They are non-excludable and non-rival in consumption: that is, it is difficult to exclude a person from using the good (such as breathing the atmosphere), and one person's use does not deny another's the use of the same good.

The reliable supply of electricity has certain public good aspects. In a network, where consumers are not restricted in their ability to demand electricity and need only pay for it later, the delivery of electricity to all consumers can be affected by the demands of others, and the supply arrangements they have made to meet their demands. Failure by some customers to make adequate arrangements in advance to supply actual demands can affect not only the reliability of their own supply, but also that of all other consumers on the same network. Conversely the willingness to pay by some, to ensure adequate security of supply, may allow others who do not pay share the benefits nevertheless; the so-called "free-rider" problem.

Traditionally, power system reliability has been managed in monopoly environment, assuming a perfectly inelastic demand for electricity. In this situation the market was conditioned to construct sufficient supply to meet all conceivable needs. In an electricity market, both supply and demand should be price-responsive, helping to ensure that the market is always able to clear. In other words, reliability may be redefined as a situation where the pricing mechanism is able to ensure a balance of supply and demand, without resorting to the rationing of electricity e.g. through rotating power cuts.

To achieve this market-based reliability requires both sufficient incentive to reduce demand and sufficient capability to do so. Pricing is the key mechanism for establishing the correct incentives; metering and data collection capable of supporting price-signalling become the main infrastructure requirements.

Table 7 below illustrates other forms of public and private goods relevant to liberalised electricity markets.

In a liberalised context, the task of internalising and aligning costs to consumer values can be thought of as turning public goods into private ones. This can be illustrated by considering the infrastructure of electricity metering and information exchange. Traditional meters typically record only energy consumption, without regard to the time it was used. Actual meter readings take place sometimes monthly, more often quarterly or even annually. Such an information flow effectively prevents the consumer from expressing a preference for value, and as such the value is not recognised: there would be no point in offering consumers a time-sensitive power price if there is no means to measure when they actually use electricity. Thus in this scenario, the metering equipment attracts no private value, but may have the characteristics of a public good. Traditional regulation accounted for basic metering, with the investment often being undertaken by a government-owned business.

Table 7

Public and Private Goods in a Liberalised Electricity Market

Attributes	
Public Goods	**Private Goods**
Security / reliability	Participant savings
Reduced price volatility	Financial/insurance hedge value
Mitigation of market power	System efficiency
Deferral of new capacity	Efficient asset utilisation
Environmental benefits	
Customer choice	

In a liberalised market it has been suggested that metering should in fact become a private good, evidenced by the emergence in some market designs of competitive metering services regulation. It was envisaged that these markets would deliver increased efficiency and technology innovation, as a service to both retail companies and network operators. In some OECD markets this has enabled metering service companies to access larger markets (beyond an existing meter company's traditional regulated footprint), enabling greater economies of scale and consequent cost savings. However, the investment model required to increase innovation and performance is often unaffected by the introduction of competitive metering services: incentives remain split between retailers engaged in potentially short-term supply contracts on the one hand, and network operators who have long term obligations to the security of network operation[36] on the other.

In certain OECD markets regulators have taken additional steps to encourage innovation through the use of minimum metering performance standards. This may be a useful policy measure to act as stimulus to investment, but is seen by some market participants as being antithetical to the model of competition, and it may not address the split incentives problem described above.

Furthermore, if the effects of metering competition are simply to lower the cost of provision of metering products, exacerbated by the emergence of more concentrated buying influences, it should be noted that the long-term quality of supplied metering products may fall as competitive metering suppliers attempt to retain their market shares and margins. Minimum performance standards would appear to be an essential requirement.

An alternate hypothesis for the provision of metering services is that metering should remain a public good or, stated another way – that an "enabling demand-side information network" will deliver public benefits including improved network security, reliability and an overall reduction in pricing to all consumers. As with the wires network, the metering network can be considered to be a public good in the sense that it enables the market, and once established, the metering network exhibits the same characteristics as the wires network: all consumers and suppliers can have access and no consumer's preference significantly impacts the cost of supply.

The primary challenge to this hypothesis is the issue of funding and investment: in the case of the wires network, much of the investment is in place; in the case of an advanced metering "network" it is not. As well as addressing the short-term increase in investment required to upgrade demand-side infrastructure, commensurate with the performance and information needs of liberalised retail electricity markets, policy design will need to ensure that both network and metering investment signals are provided in such a way as to ensure longer-term security and

36. *Ibid.*, p. 48.

reliability objectives. The absence of existing demand-side network infrastructure implies that there may be substantial start-up investment required; there is little evidence that this has been forthcoming in many OECD competitive metering service markets.

Existing network regulation allows for cost recovery of metering investments at levels consistent with reliability and security standards set by regulators. Extending this cost recovery approach to include demand-side infrastructure would address the problem of split incentives seen in current market designs; the benefits of such a development could be significant.

In the United States, the McKinsey & Company White Paper on Dynamic Pricing noted that, "...with falling technology and digital communications costs, the (metering) infrastructure needed for dynamic pricing can now be brought to the mass market, albeit with relatively long payback periods (5 to 6 years). However, since so much of the benefit of dynamic pricing is the result of collective and not individual usage, a free-rider problem threatens to prevent this deployment. By our estimates, dynamic pricing would have to be extended to one-half or more of mass market customers in order to deliver positive economics. Such a wide-scale deployment will require an institutional solution"[37].

A recent Australian report[38] has proposed an institutional solution for delivering metering infrastructure into the state of Victoria. Key recommendations, supported by comprehensive cost-benefit analysis, include the deployment of a state-wide metering infrastructure solution to include:

■ Interval meters to be installed within two years for large customers with consumption greater than 160 MWh.

■ Interval meters to be installed within 5 years for small business and residential customers (consumption < 160 MWh) with off-peak metering or 3 phase metering.

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37. White Paper – The Benefits Of Demand-Side Management And Dynamic Pricing Programs – Mckinsey & Company – May, 2001.

38. Essential Services Commission – Installing Interval Meters for Electricity Customers – Costs and Benefits Position Paper – November 2002.

- The installation of interval meters on a new and replacement basis (unless further supporting justification sufficient to justify an accelerated rollout is received, for small business and residential customers with single-phase non off-peak metering).

The results of the cost-benefit analysis show that for most customers the benefits to be gained from interval meters clearly exceed their additional costs. Efficiency gains quantified in the analysis include those arising from the avoided generation, transmission and distribution capacity costs that will be delivered by customers responding to interval meter-based price signals.

The need for an institutional solution is based upon the report's stated view that "there are insufficient incentives for retailers and customers to install interval meters in a way that will help capture demand management benefits. Accordingly, there is a role for regulatory intervention in order to realise the long-term benefits of price based demand management that these meters will help facilitate"[38].

Investment Analysis and the Payback Gap

Investment in the demand-side is often considered to be impeded by a "payback gap". This is a reference to the gap between the commercial expectations for payback for a supply-side investment, versus the payback for equivalent demand side investments, under conditions produced by liberalised markets.

Supply-side investments, typically more substantial in scale, occur in an environment where the asset utilisation is arguably more secure. Absent demand response, supply growth would continue unconstrained, with demand growth forecasts providing a relatively firm measure of utilisation risk assessment. Principle risks associated with supply side investments are more likely linked to primary fuel choices and generation technologies. However, with relatively long-term security of utilisation, coupled with the long-term position held by such investors in the electricity markets, investments are often approved with very long payback periods; typically when the rate of return falls between 5% and 10%, and over a time horizon of 15 to 25 years[39]. Options for financing

39. Stalemate in energy markets: Supply Extension versus Demand Reduction – Aviel Verbruggen, University of Antwerp, STEM (November 2002).

such investments are increased where large scale long term investments, providing relatively secure returns, enable supply investors to attract 3rd party or external financing support.

Demand-side investments tend to have the opposite profile; smaller, with a perception of higher risk and requiring shorter payback periods. Whether the risks are higher or not may depend upon consumer attitudes and perceptions of risk in the faster moving, competitive environment of energy retail. What is manifest is that retail contracts are short, providing both retailer and consumer with contracted relationships, and the securities inherent within, typically for periods of not more than a year, sometimes less. For this reason the long-term utilisation of an investment may be much less secure – an investment case may be rapidly undermined by a supply-side infrastructure investment, a change in pricing regulation or the withdrawal of a retail product. Furthermore, it should be acknowledged that energy management for demand response, for the purposes of profit, is not usually the primary business of the consumer (i.e. the consumer will have a portfolio of choices for investing for profit, against which energy management must compete). Thus, a much more rapid payback period, typically as low as 2-3 years, and in specific circumstances less, is often demanded. Such short paybacks, coupled with harder-to-quantify risks, make attracting financing, including 3rd party sources, for demand-side investments much more problematic.

The payback gap is a problem to the extent that demand side investments may not benefit from flexible financing mechanisms, but rather must be made on short term profit horizons and in an environment where taking time to evaluate risk is generally not considered by consumers to be worthwhile (not core to their business or application). In this event supply-side solutions will continue to be favoured, irrespective of whether or not they represent a least-cost path or ensure most efficient allocation and utilisation of assets.

The residual question concerning this disparity is whether there is a remedy, or a need for a remedy. While this is a wider topic than the one being treated here, regulators should at least be aware of this phenomenon and recognise that it will limit the extent to which the market, without some form of intervention, will be willing to invest in least-cost and energy-efficient solutions.

TODAY'S LOAD RESPONSE MARKET

Country Experiences – United States

■ Market Organisation

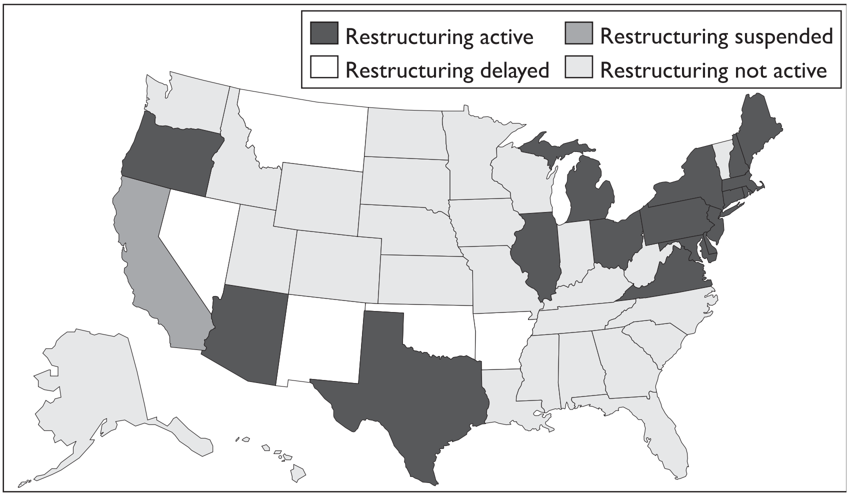
Pre-liberalisation, electricity has been provided by vertically-integrated, regulated utilities responsible for all major functions – generation, transmission, distribution and retailing. The competition model toward which the industry has been moving reflects the view that generation and energy retail services can be competitive, but the "wires" segments of the industry transmission and distribution retain natural monopoly attributes and therefore need to remain subject to regulation. The United States model consists of the following elements:

- Liberalised wholesale generation sector.
- Interstate transmission network.
- Local distribution networks.
- A competitive sector for retail power and energy services.

The status of United States electricity market reform varies from state to state, being actively pursued in 18 states, delayed in 4 states and not yet active in 27 states (Figure 4). Reform has been suspended completely in

Figure 4

Status of State Electric Industry Restructuring Activity (February 2003)[40]



40. Source – United States Department of Energy.

California after the State of California was required to intervene to correct market failures, restore pricing stability and security of supply.

Federal Regulation

The U.S. Department of Energy is the ministry responsible for general energy policy, and specifically for energy security, environmental quality, and science and technology related to energy.

Generally, interstate activities (those that cross state lines) are subject to federal regulation, while intrastate activities are subject to state regulation. Wholesale markets (sales and purchases between electric utilities) are federal concerns. Approval for most plant and transmission line construction and retail rate levels are state regulatory functions.

The Federal Energy Regulatory Commission (FERC) has taken a strong lead in recognising the role to be played by the demand side, and particularly the implications for market design. FERC is currently engaged in an open consultation with the Independent System Operators (ISO) in order to establish the regulatory implications for the further development of demand side solutions within the Standard Market Design (SMD).

"Demand response is essential in competitive markets to assure the efficient interaction of supply and demand, as a check on supplier and locational market power, and as an opportunity for choice by wholesale and end-use customers". [41]

A recently-issued FERC consultation docket[42] relating to demand response issues has sought market facts and opinions from Independent System Operators currently operating Demand Response programs. These issues for consideration within FERC's Standard Market Design can be broadly grouped into two categories:

Pricing

A principle regulatory consideration continues to be centred on the question of pricing for demand response solutions in the competitive

41. *FERC Working Paper on Standardized Transmission Service and Wholesale Electric Market Design, March 15, 2002.*

42. *United States of America Federal Energy Regulatory Commission, Demand Response Programs Docket No.Ad02-23-000 Notice Of Presentation On Demand Response Issues And Request For Public Comment (September 20, 2002).*

market, and particularly in the role of pricing to provide longer-term incentives. This is consistent with the role of federal regulation and its responsibility toward maintaining long-term security of supply through network investments and capacity planning.

The response to the FERC consultation process suggests that pricing has a key role to play, but that in competitive markets, subsidies and socialisation of costs should not be required in the longer term to support demand response activity. This implies that those responding, principally the Independent System Operators, believe that subject to efficient longer-term market design, the markets themselves should decide on the value of and role for competitive demand response services, without regulatory assistance.

Market Design and Infrastructure

The United States electricity market is in a state of transition, as well-illustrated in Figure 4. Wholesale electricity markets await the delivery of Standard Market Design, whilst deregulation in retail markets varies from state to state. Federal regulation of wholesale markets and state regulation of pricing at the retail level have been shown to cause market imperfections. The recent experience in California[43] illustrates the natural interdependence of the wholesale and retail markets and the challenges for regulation in such an environment.

FERC views its role as focusing on long-term resource adequacy requirements as a major element in long-term price stability. Recognising that demand response has a key role to play in mitigating price spikes, the FERC recommended minimum 12% resource adequacy margin can and should include demand response.

State Regulation – Public Utilities Commissions (PUCs)

State public service commissions have jurisdiction primarily over the large, vertically-integrated and investor-owned electric utilities that own more than 75% of the nation's generating and transmission capacity, which serve about 75% of ultimate consumers. Although the responsibilities vary from state to state, public utility commissions have a

43. *P. Joskow et al. (2001, 2002).*

mandate to supervise and regulate all utilities within state and to develop rules and measures consistent with market liberalisation plans. Specific regulatory activities may include:

- Setting rates for electricity and distribution services.
- Regulating service standards.
- Monitoring utility operations for safety.

Transmission and Distribution

In the United States, investor-owned utilities (IOUs) own 73% of the transmission lines; federally owned utilities own 13%; and public utilities and cooperative utilities own 14%. Not all utilities own transmission lines (i.e., they are not vertically integrated), and no independent power producers or power marketers own transmission lines. Over the years, these transmission lines have evolved into three major networks (power grids), which also include smaller groupings or power pools. The major networks consist of extra-high-voltage connections between individual utilities designed to permit the transfer of electrical energy from one part of the network to another. These transfers are restricted on occasion, because of a lack of contractual arrangements or because of inadequate transmission capability.

Wholesale Markets

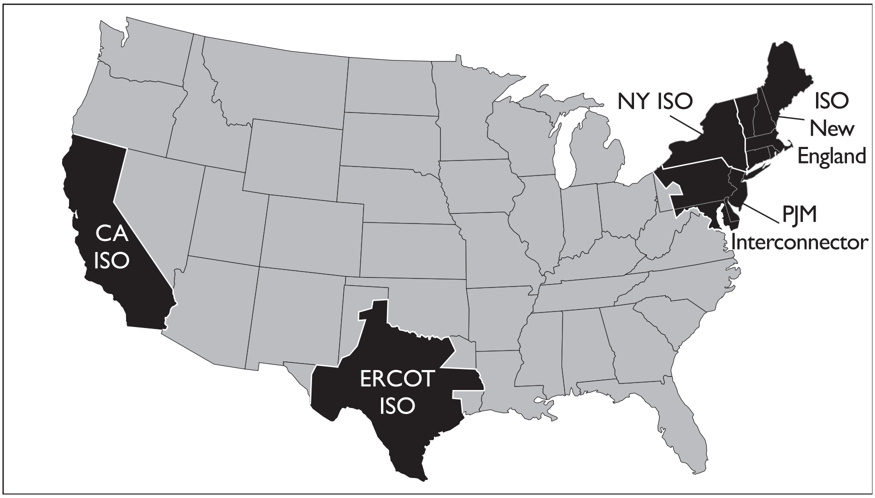
The United States has considerable experience in the operation of both System Led (Emergency) and Market Led (Economic) demand response programs in its wholesale or bulk power markets, where approximately half of all electricity generated is purchased (or traded) before being sold to ultimate consumers.

Wholesale transactions allow utilities to reduce power costs and increase power supply options. During contingency and emergency situations, overall electric system reliability is maintained as utilities co-operate in wholesale trade.

The bulk power system has evolved into three major networks (the interconnected Eastern, Western, and Texas power grids) which consist of extra-high-voltage connections between individual utilities designed to permit the transfer of electrical energy from one part of the network to another. Independent System Operators have emerged to operate the wholesale markets which are now in operation as shown in Figure 5 below.

Figure 5

U.S. Independent System Operators in Operation, 2000



Retail

The retail, or end user market, is served in the United States by electric utilities. The 3,170-plus traditional electric utilities in the United States are responsible for ensuring an adequate and reliable source of electricity to all consumers in their service territories at a reasonable cost. Electric utilities include investor-owned, publicly-owned, co-operatives and federal (government-owned) utilities. Power marketers are also considered electric utilities; these entities buy and sell electricity but usually do not own or operate generation, transmission or distribution facilities. Utilities are regulated by local, state and federal authorities.

There are 239 investor-owned electric utilities, 2,009 publicly owned electric utilities, 912 consumer-owned rural electric cooperatives, and 10 federal electric utilities in the United States. Approximately 20 States regulate co-operatives and 7 States regulate municipal electric utilities; many State legislatures, however, defer this control to local municipal officials or co-operative members.

Demand Response Programs – Wholesale

The United States' market has a long history of using contracted load-shifting demand resources, delivered as part of utilities' efficiency commitments under demand side management programs. These demand response products, illustrated in the Table 8 below, fall into two general categories: "emergency programs" that respond to system reliability concerns, and "economic programs" that enable demand-side consumers opportunities to sell back load or demand at times when wholesale market prices make an economic case.

Table 8

US Demand Response Product Types

	Program Type	
DR Product	**System Led (Emergency)**	**Market Led (Economic)**
Legacy DR Products (DSM)		
Direct Load Control	✓	
C&I Interruptible Rates for Non Firm Service	✓	
New Products		
Call Type Programs	✓	✓
Demand Side Bidding Programs	✓	✓
Dynamic Pricing	✓	✓

Three of the four existing FERC-regulated Independent System Operators – PJM[44], New York (NYISO), and New England (NE ISO) have demand response programs in place[45]. Table 9 below illustrates the current state and scale of existing demand response program activities across the Independent System Operators.

44. PJM is the ISO company name. PJM provide system operation for all or parts of Delaware, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia and the District of Columbia..

45. New England Demand Response Initiative – Demand Side Resources And Reliability Framing Paper – Eric Hirst & Richard Cowart – March, 2002.

Table 9

US Demand Response Key Performance Indicators

	Market Metrics				
Market Operator	**Supply (MW)**	**Peak Demand (MW)**	**Capacity Reserve**	**Demand Side Ratio**	**Demand Side Resources (MW)**
New England ISO	28,000	25,348	9.5%	0.40%	112
PJM	67,000	62,445	6.8%	Data not available	Data not available
NYISO	35,961	30,664	14.7%	4.12%	1481[46]

Program designers have been working to acknowledge the role that demand response resources can play in mitigating network constraints. Department of Energy and FERC reports indicate that there are serious transmission bottlenecks in all parts of the country, including where Independent System Operators exist, because of a lack of investment in transmission capacity. Data from the North American Electric Reliability Council (NERC) shows steady declines over the past decade in transmission capacity relative to demand. In 2000, normalised capacity relative to demand was 17% lower than it had been a decade earlier. The trends, which are not restricted to any particular region, are projected to continue for the next decade.

The costs of inadequate transmission are substantial. The DOE conservatively estimated the costs of transmission congestion in the California, PJM, New York, and New England Independent System Operators at about $450 million per year. FERC found that costs of congestion in New York in the summer of 2000 alone were over $700 million. The introduction of locational marginal pricing by the Independent System Operators will enable the distributed nature of demand response to be recognised as a valuable resource to this market.

46. *Load committed not necessarily participated.*

Emergency Programs

Emergency programs in the United States are largely based on typical pre-liberalisation load management programs operated by vertically-integrated utilities. Designed to provide contingency response to supply shortages and network congestion, there are now over 15,000 MW in place in the United States market, operating in both wholesale and retail markets.

These special reliability markets procure contingency-reserve services from loads. The Independent System Operators established these as separate markets, rather than encouraging retail loads to participate in ancillary service markets, for a variety of reasons. PJM has no markets for reserves, while New England recognizes serious limitations in its ancillary service markets[47]. More generally, market participants probably felt that the metering and telecommunications requirements for participation, in what had historically been generation-only functions, were too onerous. Whether these demand-management pilot programs disappear after the Independent System Operators create and modify their markets to encourage retail-load participation, or whether they will become permanent features, is currently uncertain.

The programs usually involve reserve or capacity payments, penalties for non-performance, and are designed to be designed to be dispatchable, operating only for short periods, typically less than 100 hours annually.

Programs operated by the four Independent System Operators during summer 2001 contributed 1,078 MW of subscribed load of which 618 MW[48] participated during curtailment events. Summer 2002 performance has been slightly higher in some cases, as shown in Table 10.

Emergency programs are called according to system operators' emergency operating rules rather than being subject to a commercial business case, which is why they are not classified as "economic". New England Independent System Operator customers are required to reduce

47. The markets for spinning and supplemental reserves in New England are, as the ISO itself put it, "fundamentally flawed" (ISO New England 1999). In addition, even though ISO New England acquires more than 1,000 MW for the equivalent of replacement reserves on most days, it has no formal market to acquire those resources.

48. This figure includes 142 MW of participating load for CAISO the Demand Relief Program and the Discretionary Load Curtailment Programs which were not operated during 2002.

Table 10

US System Led / Emergency Demand Response Program KPIs (Key Performance Indicator)

2002 Performance					
Market Operator	**Enrolled Participants**	**Number of Events/ Periods**	**Total Load Curtailments (MWh)**	**Average Load Curtailment (MW)**	**Average Payment ($/MWh)**
New England ISO	79	0	0	0	0
PJM	–	14 hours	551	39	513.60
NYISO	1,711	32 hours	5,941	668	500.00[49]

load after a Second Contingency Loss[50] or following the implementation of voltage reductions, to maintain system reliability. However, according to a recent evaluation report[51] produced for the NYISO Emergency Demand Response Program, the economic benefits of such programs are significant. The evaluation considers economic benefits in the following terms:

- **Reliability benefits.** These measure the effect of load reductions on system reliability as valued by the decrease in expected un-served energy; that is, how an increase in reserves would reduce the likelihood of a forced outage and thereby reduce the costs customers incur when service is interrupted. These benefits are enjoyed directly by all end-use customers.

- **Collateral savings.** Demand response reduces market prices and transfers revenue flows from generators to wholesaler buyers during these emergency conditions.

- **Hedging benefits.** Hedging costs are reduced, reflecting the longer run impacts of lower price variance resulting from program curtailments.

49. Payment is higher of $500 or Locational Marginal Price.

50. NEPOOL Operating Procedure No. 8 defines Second Contingency Loss as the largest capability outage (MW) which would result from the loss of a single element after allowing for the First Contingency Loss.

51. 2002 NYISO PRL Evaluation, Neenan Associates.

According to the NYISO study the total program costs of $3.3 M were offset by collateral savings of $577,000, hedging benefits of $370,000 and reliability benefits which were estimated to range from $1.7 M to $16.9 M[52].

Economic Demand Response Programs

Economic programs are those that enable the customer to make a commercial decision to participate, conditional upon an economic threshold signalled by the prevailing market price for power. Such programs are generally voluntary, although prior enrolment and

Table 11

Wholesale Electricity Markets and Demand Response Resources[53]

Market	Description	Demand Response Resources
Day-ahead Energy	Load Serving Entities (LSEs) submit orders for day-ahead contracts; Suppliers submit bids to make un-obligated capacity available to LSEs; ISO schedules generation to meet loads in economic merit order subject to security-constrained unit commitment constraints	Scheduled Price-Responsive Load (PRL)
Real-time Energy	Suppliers submit bids to provide balancing energy that are dispatched to meet residual LSE requirements; ISO dispatches according to economic merit order (i.e., minimize cost of meeting electricity demand with resources then online or which can be started quickly)	Dispatchable Price-Responsive Load
Day-ahead Ancillary Services	Potential suppliers submit capacity, energy bids to supply various ancillary services (e.g., supplemental reserve, replacement reserve, spinning reserve, regulation, frequency response)	Dispatchable PRL that meets dispatch/curtailment requirements for ISO ancillary services

52. System reliability benefits were analysed using a range of values for outage costs and the reduction in Loss of Load Probability (LOLP) to bracket the likely, but unobserved, actual values. Assuming an average outage cost of $5,000/MWh and that 5% of the load was at risk due to a reserve shortfall, the reliability benefits were estimated to range between $1.697 million and $16.9 million, depending on the assumed level of reduction in LOLP at the level of 0.05 and 0.50, respectively.

53. Neenan Associates 2002. Valuing Investments in Developing Customer Price Responsiveness. Hirst, E. 2002 Reliability Benefits of Price-Responsive Demand.

qualification is usually required. Bidding can take place in either the day-ahead or real-time markets and the typical programs are characterised in the table below.

Table 12

US Market Led / Economic Demand Response Program KPIs

2002 Performance					
Market Operator	**Enrolled Participants**	**Number of Events**	**Accepted Bids (MWh)**	**Average Payment ($/MWh)**	**Average Payment LMP/MCP**
New England ISO	146	12[54]	75 MW enrolled in program, but participants do not bid, participation is volontary from program opening	234.37	93.46[55]
PJM			6462	117.92	118.12
NYISO	24		1486	Greater of bid in$MWh and DAM LBMP	n.a.

The propensity of qualified participants to engage in these programs will depend upon prevailing market prices and their organisational capability to respond during times of high prices. Performance of these programs in the summer of 2001 was modest at best, and more often insignificant. Their limited performance may have been a result of the newness of the programs, design features and possible barriers to acceptance[56]. A further reduction of participation was seen in the summer of 2002, as shown in the table below, with this reduction probably linked to low market prices and the maintenance of retail price caps.

54. New England ISO Economic Demand Response Program activations in 2002. Once the economic program is activated for a day, the program remains open until 23.00 hrs. Thus the number of events is equal to the number of days that the program was called.

55. New England ISO LMP/MCP is actually the Energy Clearing Price for the hours the program is activated, calculated as a simple average of the hourly price for the program hours.

56. See E. Hirst, Barriers to Price-Responsive Demand in Wholesale Electricity Markets, Prepared for the Edison Electric Institute, June 2002.

Evaluating the performance of economic programs is complex, since considering the customers' business case requires an appreciation of the value to the customer of their consumption at specific points in time.

As with emergency programs, there will be economic impacts beyond the immediate individual contract transfers. For example, the collateral benefits of the NYISO day-ahead program, measured as the price decline associated with demand response bids multiplied by the load scheduled in the day-ahead market, amounted to some $236,000 (with the benefits shared by all participants in the day-ahead market).

■ Demand Response in Retail Markets

It is difficult to capture a comprehensive picture of the status of demand response at the regional retail level, since deregulation and changes in market organisation in the United States have impacted upon the channels through which demand response activities were reported. In liberalised markets, retailers are not obliged to provide full transparency of reporting in relation to individual products or contract positions.

Demand response at the retail level can be achieved using price signalling through traditional interruption contracts, buy-back products and real-time pricing tariffs. Real-time and time-of-use prices for residential electricity customers have yet to gain widespread acceptance. This is in spite of their potential to save consumers over $1.2 billion per year in California alone, according to the Electric Power Research Institute. In an EPRI study, over half of the 123 investor-owned utilities surveyed offered residential time-of-use tariffs, yet less than 1% of their customers subscribed to these rates. None offered real-time prices[57]. While the number of utilities now offering time-based pricing has increased, the percentage of their customers receiving these prices has not changed a great deal since the survey[58].

57. "Time-of-use" prices have a peak, sometimes a mid-peak, and an off-peak price for a maximum of three prices per month. "Real-time prices" vary as frequently as every hour, though prices for residential consumers are typically limited to four or five, adding a "super peak" and a "critical peak" to the normal TOU periods. The super peak and critical peak prices are dispatchable, meaning they can be turned on or off on a daily basis (the normal situation is that they are off, turned on when wholesale prices rise significantly).

58. The Economics of Real-Time and Time-of-Use Pricing For Residential Consumers, Chris S. King – June 2001.

Results of time-based pricing continue to demonstrate the beneficial impact that innovative rate structures have on reducing residential peak load: historical analysis of residential time-of-use data at Connecticut Light & Power, Pacific Gas & Electric, Wisconsin Public Service, Narragansett Electric Company and Wisconsin Electric Power have shown significant consumption reductions during peak periods of approximately 23%, 18%, 15%, 7% and 4% respectively.

Energy Information Administration (EIA) data (Table 13) give an indication of demand side management-related (load reduction) activity by utilities levels for the period 1996-2000. It can be observed that the pace of actual reductions has reduced over time. This may be in part due to the relative lowering of retail price, a corollary of the effect of fierce price competition. An additional contributing factor can be traced to how demand side management charges are raised and how programs are reported. In California for example, utilities report demand side management activities and cost to the EIA through the California Board for Energy Efficiency (CBEE), whereas in New York some demand side management activities are carried out by New York New York Energy Research and Development Authority (NYSERDA) funded through a systems benefit charge and hence not reported by utilities.

Programs offered by Portland General Electric, Georgia Power and Duke Power are particularly innovative and provide good examples of "best practices" of demand response products among utilities (Goldman et al 2002).

Table 13

DSM Measures – Peak Load Management[59]

Item	1996	1997	1998	1999	2000
Actual Peak Load Reductions (MW)*[60]	29,893	25,284	27,231	26,455	22,901
Potential Peak Load Reductions (MW)	48,344	41,237	41,430	43,570	41,369

59. Source: DOE/EIA-0348(00)/2 Electric Power Annual 2000 Volume II – November 2002 (Table 39).

60. Represents the actual reduction in annual peak load achieved by consumers, at the time of annual peak load, as opposed to the installed peak load reduction capability (Potential Peak Reduction).

Portland General Electric's (PGE) Demand Buy Back Program is a voluntary, "quote-type" demand bidding program. In 2001, PGE offered the Demand Buy Back Program with three types of load reduction bidding variants: day-ahead, pre-scheduled (up to one week in advance), and term events (lasting weeks to months). As of September 2001, the program had 26 participants with 230 MW of potential curtailable load. Customers as small as 250 kW were invited to participate, although over two-thirds of the participants were over 500 kW.

PGE has had significant success in eliciting a substantial demand response from participants. From July 2000 to May, 2001, there were 122 daily events, resulting in average load reductions of 162 MW. In December 2000, when offers to participants reached $300/MWh, the full potential load reduction was curtailed, representing 50% of the participants' collective summer peak demand. A significant basis for their success has been that PGE worked with each participant individually to identify specific load curtailment strategies and quantify the associated load reduction. A further factor (not at all incidental) was that the program was launched in time to capitalise on the extreme wholesale electricity prices in the United States West Coast.

Table 14

California Interruptible Load Programs Summary [61]

Program	MW	Notes
Traditional Interruptible	1,043	
Base Interruptible (BIP)	40	
Demand Bidding (DBP)	22	
Optional Binding Mandatory Curtailment (OBMC)	19	
Scheduled Load Reduction (SLRP)	4	
Agricultural Pumping	41.5	SCE only
Rolling Blackout Reduction (RBRP)	52	SDG&E only
Pilot OBMC	2.5	PGE only
AC Cycling	247	SCE only
Total Contribution	1,470	

61. Source: CPUC's Interruptible Load Programs Decision Summary (Decision 02-04-060, Rulemaking 00-10-002).

By purchasing these load reductions, PGE was able to avoid more expensive purchases in the wholesale market to cover net short load and/or sell any excess generating capacity into the market.

When combined with programs offered within state at Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E), California has 1,470 MW of load reduction available from interruptible demand response programs (Table 14).

The real-time pricing programs operated by Georgia Power and Duke Power indicate significant demand response when prices hit or exceed the $350-$500/MWh level. For example, in August 1999 when Georgia Power's real-time prices exceeded $1,000/MWh, customers responded by reducing load by about 800 MW (out of a total of about 5,000 MW participating on real-time-pricing) or about 20%[62]. While prices in the South-east never reached that level in 2001, the 1999 Georgia Power maximum real-time-pricing load response was greater than the combined maximum load response from all the Independent System Operator demand response programs in 2001.

Conclusions – United States

The United States market for demand response is amongst the most advanced in operation in any liberalised OECD market. Valuable technology, commercial and operational lessons have already been learned; consumers, retailers and system operators have all engaged in what will be seen as the first generation of demand response activity in a liberalised electricity market. Through innovation in program design, application of advanced technologies and software, the Independent System Operators and utilities have engaged all consumer classes in demand response activity, from dynamic pricing in the residential sector, to sophisticated buy back programs for large industrial customers.

However, challenges remain and a primary one is that of scale – most programs operated by Independent System Operators and utilities are too modest in scale to have sustainable or significant impacts on wholesale price setting or longer-term average prices.

62. S. Braithwait and M. O'Sheasy, "Customer Response to Market Prices – How Much Can you Get When You Need It Most?" EPRI International Pricing Conference 2000, Washington, DC, July 2000.

At the federal and system operation level, FERC and the Independent System Operators respectively have duly considered the value and role of the demand side. However it is the utilities, in turn regulated by utility commissions, which ultimately carry the responsibility for retail price determination. In this pricing environment the introduction of competition appears not to have further stimulated growth or further development of price-response tariffs. This situation may be in part accounted for by the volatility of pricing in the wholesale markets. Consumers are looking for stability, and where innovation in tariffs is proposed, they seek a clear economic advantage. Faced with uncertain wholesale prices, utilities and state regulators will find the design and implementation of new tariff products a considerable challenge. As the wholesale markets mature, and the ability to forecast prices increases, the value of dynamic pricing programs should become easier to model.

Evaluation of existing Independent System Operator programs has demonstrated that significant benefits are available to the system in terms of reliability, capacity planning and transmission relief, and yet many of these benefits are not captured financially or incorporated in the wholesale-retail pricing model. New Independent System Operator program designs are working to recognise the unique nature of demand response resources. Independent System Operators that were based on existing power pools (ISO-NE, NYISO and PJM) were designed to manage large physical assets, such as transmission networks and generation resources, and have significant contractual, technical and operational issues to address.

Independent System Operators appear to have realised the benefits of the introduction of intermediaries to solve some of these challenges. Curtailment Service Providers (CSPs), operating as aggregators in today's wholesale electricity markets, are well-placed to streamline the interfaces between the smaller, relatively uninformed customers, and the day-to-day business of Independent network operation. Aggregation of services will play a key role in the further development of Independent System Operator programs, providing access to customers who may otherwise not be able to participate.

From the perspective of the large industrial or commercial enterprise, the varying degrees of access to demand response markets across states presents an additional problem for potential growth. Potential participants are faced with multiple demand response program designs, making the task of engaging in multiple-state programs inordinately complex. Federal attention to the role of demand response within Standard Market Design, for states which pursue liberalisation and implement the model, may deliver some much needed consistency to programs offered by Independent System Operators.

A further consumer concern relates to settlements, and specifically the speed and timing of payments. Payments to customers for load reductions are often very late, and in some cases payments for performance are not made for several months. The speed of the payment cycle is often based on traditional Independent System Operator supply side settlement timetables which, while suitable for capital intensive long-term supply-side businesses, do not deliver payments consistent with traditional demand-side finance and budget management requirements.

Finally, the question of subsidisation of demand response remains contentious. Subsidisation may be justified where basic customer economic criteria are not met, yet the public good benefits justify intervention. Many demand response practitioners hold that subsidisation is necessary for adequate cost recovery. Such cost recovery could extend to program costs, incentives to customers and possible lost revenue. The need for subsidisation however, should continue to be questioned. Recent evaluation work has suggested that programs that focus on contract positions and financial transactions are able to deliver robust business models accounting for both the load reduction and the wholesale market impacts[63].

■ Key Conclusions – United States

Pricing – Retailers and regulators should examine the relative merits of flat and variable retail rates during periods of wholesale market volatility and constraint, and during periods of wholesale price stability. Since markets have been seen to transition rapidly from one state to another, it is important to evaluate the impacts of regulated rate caps and fixed default service rates under both conditions. Recognising that the modest level of demand response in evidence in current markets will fail to deliver

63. Demand Response is Important – But Let's Not Oversell (Or Over-Price) It -Steven Braithwaite Laurits R. Christensen Associates, Inc. March 31, 2003.

significant impacts on wholesale price, retail companies and state Public Utility Commissions should further research the potential impacts of transitioning large numbers of targeted customers onto dynamic pricing.

Market Access – Market designs should address the role of third-party aggregation. While third-party aggregation of load curtailment will be key source of new demand response and innovation, particularly for smaller customers, there are fundamental issues associated with bypass, revenue impact, and cost recovery that will need to be explored and evaluated.

Standardise Program Design – Independent System Operators should be encouraged to support the development of standard market designs for demand response and work collaboratively to ensure maximum market access for participants. Greater customer participation would likely occur, particularly from large national chains and corporations, if these customers did not have to track and understand multiple program offerings. It should be acknowledged that standardisation of market design may initially counter innovation in specific markets, but the benefits of increased participation of demand response providers will ensure long-term markets are established in which innovation can subsequently develop.

Settlements – Utility and Independent System Operator program providers should ensure that settlements procedures are not biased towards supply-side processes, but are optimised where possible for demand-side business practices.

Regulation – Ensure that utility and Independent System Operator demand response programs are coordinated and can co-exist. Independent System Operator programs are important new options for incorporating demand response into electric markets. Nevertheless, the implementation of these programs needs to be conducted in a manner that does not negatively impact on existing utility load management programs.

Country Experiences – England and Wales

■ Market Organisation

The United Kingdom market liberalisation process, which was begun in 1990, has created a highly competitive market in which suppliers can sell energy nationwide and all customers can choose their electricity supplier. Competition is underpinned by open access to the grid and distribution networks on non-discriminatory terms, both in relation to granting the use of the system and the charges.

In England and Wales the monopoly elements of the business – transmission and distribution – have been separated from those which are subject to competition – supply and generation.

Government

The United Kingdom Department of Trade and Industry's Energy Group deals with a wide range of energy-related matters, from production or generation to its eventual supply to the customer. It has recently issued its long-term strategic vision for energy policy in the Energy White Paper[64]. This document sets out the latest government thinking on climate change strategy and recognises energy efficiency as the least-cost solution for the delivery of its Kyoto commitments.

Regulation

The Office of Gas and Electricity Markets (OFGEM) is the regulator of gas and electricity industries in Great Britain. OFGEM operates under the direction and governance of the Gas and Electricity Markets Authority, and is responsible for all major decisions and policy priorities. Its powers are provided for under the Gas Act 1986, the Electricity Act 1989 and, most recently the Utilities Act 2000. The regulator also has powers under the Competition Act 1998.

Supply – Generation

There are now thirty-five companies regarded as major power producers; following early reductions, recent trends have shown an increase in market concentration with the top three suppliers now accounting for 53.2% of market share.

Demand – Retail

The introduction of competition was phased in over eight years because of the sheer size of the task, including the number of customers and the

64. *"Our Energy Future – Creating a Low Carbon Economy" – DTI, February 2003.*

technical complexities involved. The first tranche of the electricity market, covering about 5,000 large customers with a maximum demand of 1 MW and above, was opened to competition in April 1990. Ten years later 81% of customers in this market were supplied by a non-local supplier. In April 1994 the second tranche of the market, covering about 50,000 medium size customers with a maximum demand of 100 kW-1 MW, was opened to competition.

The last and largest tranche of the electricity market covering about 26 million customers with an annual consumption of up to 12,000 kWh, including domestic and small business customers, was progressively opened up for competition between September 1998 and May 1999.

Transmission and Distribution

National Grid Company (NGC), the transmission network operator in England and Wales, has a central role in the industry. It has a statutory duty to develop and to maintain an efficient, co-ordinated and economic transmission system, and to facilitate competition in supply and generation. NGC must ensure that the system in England and Wales is balanced nationally and locally at all times, taking into account and resolving any constraints on the transmission network.

Distribution remains a monopoly business and under the Utilities Act 2000 it has become a separately licensable activity. Distribution companies hold separate licences in respect of each area and are governed by the terms of their distribution licences. They are under a statutory duty to connect any customer requiring electricity within a defined area and to maintain that connection. The Utilities Act places other statutory duties on Distribution Network Operators (DNOs) requiring them to facilitate competition in generation and supply, to develop and maintain an efficient, co-ordinated and economical system of distribution and to be non-discriminatory in all practices.

Wholesale Electricity Market Operations

The Electricity Pool of England and Wales

The Electricity Pool of England and Wales was created on March 1990 and has subsequently been replaced by the New Electricity Trading

Arrangements (NETA). The Pool was a contractual arrangement entered into by generators and suppliers that provided the wholesale market mechanism for trading electricity. The Pool did not itself buy or sell electricity; those trading in the Pool did so against a defined set of rules known as the Pooling & Settlement Agreement (PSA), which governed the constitution and operation of the Pool and the calculation of payments due to and from generators and suppliers.

Almost all electricity generated had to be bought and sold through the Pool -generators bid into the pool on a daily basis, providing a quantity and price of supply for each half hour period of the day. National Grid Company, acting as system operator, would estimate the total electricity demand for England and Wales for each half hour based on such factors as historic demand levels and weather conditions, and would call supply bids to match demand.

Price was determined by stacking the bids from generators in ascending order of price together with bid quantity. The price of the highest bid in the stack required to meet the estimated demand for the half-hour period concerned would become the basis of the Pool price paid for generation in that period, known as the system marginal price (SMP).

Normally, all supply resources called received the same payment from the Pool for each unit of electricity produced. This was equal to the system marginal price plus a capacity payment, and was known as the Pool Purchase Price, or PPP.

Suppliers buying electricity from the Pool were required to pay the Pool Selling Price, or PSP. This included an additional overhead or uplift over and above PPP which covered the cost of running the Pool, as well as payments – mainly to generators – for ancillary services provided to ensure the secure and stable operation of the grid system.

To reduce exposure to fluctuations in Pool Purchase or Pool Selling Price, generators and suppliers also entered into so-called Contracts for Differences (CFDs). These were forward contracts which would contain an agreed strike price for a specified quantity of electricity and a specified period of time. Cash payments were made between generator and supplier to cover differences between the actual Pool prices and strike prices.

The New Electricity Trading Arrangements (NETA)

Following an extensive period of regulatory review and industry consultations, begun in July 1998, the Pool was replaced by the New Electricity Trading Arrangements, or NETA, in March 2001.

Under NETA, bulk electricity is traded between generators and suppliers through bilateral contracts and on power exchanges i.e. outside of what was the Pool. Generators and suppliers notify National Grid of their respective one day-ahead trading positions for each half hour period, and may also make bids and offers into the Balancing Mechanism (BM). Participation in the Balancing Mechanism is on a voluntary basis, but those wishing to participate must sign the Balancing System Code (BSC), which provides a set of rules to ensure efficient balancing of the system. Generators are out of balance if they cannot provide all the electricity they have contracted to provide, or if they have generated too much. Similarly, suppliers who have not contracted enough electricity to meet their customers' needs or who have not consumed the amount of electricity that they have contracted for, will be out of balance. Participants who are out of balance, and therefore potentially imposing balancing costs on the system operator, are charged imbalance prices.

Thus one of the key features of NETA is that unlike the former Pool, where National Grid Company centrally despatched generating plant, generators now self despatch and are subject to imbalance prices if their generation does not match their contracted output – NETA is often referred to as being an "imbalance market".

Suppliers and generators who are out of balance are exposed to the System Buy Prices (based on the cost to the system operator of buying generation or load reduction) and System Sell Prices (based on the cost to the system operator of selling excess generation) depending on whether they are over-contracted ("long") or under-contracted ("short"). It has generally been more expensive for the system operator to call on additional flexible generation or demand reduction (which feed into System Buy Prices) than it has been to ask for bids from generators to remove generation from the system (which feed into System Sell Prices). Thus market participants have been keen to avoid imbalance exposure to the System Buy Price. Suppliers have typically chosen to be over-contracted at Gate Closure[65] and generators have chosen to part load some of their plant so that they can increase their output to cover any unforeseen outages in their plant which might leave them short of supply obligations.

The system operator procures Balancing Services to service this out of balance condition; where currently about 2% of electricity demand is bought and sold[66].

The regulatory Transmission Licence defines Balancing Services as:

- Ancillary Services.

- Offers and bids in the Balancing Mechanism (BM), which opens at Gate Closure, for NGC to accept offers of and bids for electricity to enable it to balance the transmission system. The BM allows suppliers, customers, and generators to offer bids (generation reductions and demand increases) or offers (generation increases and demand reductions).

- Other services available to the Licensee which serve to assist the Licensee in operating the Licensee's Transmission System in accordance with the Act or the Conditions and/or in doing so efficiently and economically.

The price paid, or charged, to "out of balance" market participants varies according to market conditions. The price is calculated as the volume-weighted average price for each half hour. The costs for the provision of these services, including costs of any forward contracts, are recovered from all participants through Balancing Services Use of System (BSUoS) charges on the basis of their metered generation and consumption.

ELEXON, a wholly-owned but uncontrolled subsidiary of National Grid, was established to be responsible for the operation of the Balancing and Settlements Code. ELEXON's role includes the management of the contracts with providers of NETA services, administration of the new

65. In relation to a settlement period, the time before the start of that settlement period. It defines the moment when bilateral contracting ends and the Balancing Mechanism for each associated trading period begins. Set on Go-Live at 3.5 hours before real time, and since reduced to 1 hour.

66. New Electricity Trading Arrangements (NETA) – One Year Review 2002 Fact sheet.

arrangements and processing of proposed modifications to the Balancing and Settlements Code and market rules.

Power Exchanges

The introduction of NETA has resulted in the rapid development of a large, transparent wholesale market, similar to the way in which other commodities are traded. Forwards, futures and spot markets are evolving in response to the requirements of participants and a number of power exchanges have been established, where buyers and sellers come together to trade energy and energy-related products.

There are three main power exchanges that have developed since the introduction of NETA: the United Kingdom Power Exchange (UKPX)[67], the United Kingdom Automated Power Exchange (APX) and the International Petroleum Exchange (IPE). Of these, the UKPX and United Kingdom APX provide a spot market while the UKPX and IPE both offer futures contracts. The vast majority of trading on the exchanges has been through the spot markets, with participants actively using these markets to fine tune their contractual position as their uncertainty reduces. The power exchanges are open 24 hours per day, seven days a week with access available either through the Internet or by leased line.

Demand Response Experiences – Wholesale Markets

Demand Response under the Pool

Under the Pool, suppliers were treated as price-takers and were required to purchase most of their requirements through the Pool at a common clearing price. Therefore, there was little incentive for active participation from the demand-side. Direct participation by the demand-side in the Pool was limited to a handful of large customers via:

- Load reductions at times of peak demand as a means of reducing their exposure to transmission charges.

- Contracts with NGC for the provision of ancillary services, such as standing reserve and frequency response via the Pool's Demand Side Bidding Scheme.

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67. The UKPX is the largest exchange in terms of volume traded. It currently trades in the region of 850,000 contracts a month, representing about 430 GWh of electricity.

- Contracts with their local suppliers for load management.

In practice demand-side bidders only had a minimal effect on Pool prices and did not provide effective competition to generators. Generators bidding into the Pool were, therefore, confronted with a supply-demand curve where demand was highly unresponsive with respect to the clearing price; this despite the fact that, lying behind the trading arrangements, was a set of large buyers who in other circumstances could have been expected to be eager to negotiate keener prices. Thus the Pool did not allow large buyers to "connect" with their suppliers in ways that are typical of other markets.

Forward contracts, or Contracts for Differences (CFDs), under the Pool provided some potential for suppliers to participate in the price-determination process. However, in negotiations a generator always had the option of selling electricity via the Pool, whereas demand-side influences were weaker. This strengthened the bargaining position of the generator, and made them less willing to discount prices from average Pool prices, at least so long as there was a prospect over the relevant period, of higher Pool prices. In addition there was limited transparency and price reporting of the CFDs that were in place. Overall, the lack of demand side pressures in the Pool served to the hand of buyers in the negotiation of longer-term supply contracts.

Even where supply competition was vigorous, as in the industrial and commercial sectors, the impact of demand-side pressures on wholesale prices from suppliers was limited. Around 200 of the largest demand sites (out of the approximately 5,000 1 MW + customers) acted as demand-side bidders under the Pool. Under the original terms of the Demand Side Bidding Scheme, bidders were able to avoid capacity payments equivalent to their bid capacity, even in the event that the bid was not called. In 1998/99, this capacity payment relief amounted to 0.1 p/kWh. For some larger customers this relief yielded a reduction in their electricity bills, in the region of 14%. There is no public data available to demonstrate the extent to which these customers' bids were accepted, but the avoidance of capacity payments, particularly during peak periods, could have created a free-rider problem – demand side participants bidding high into the system, high enough not to be called, yet still able to claim relief on capacity payments.

Demand Response under NETA

Increasing the role of the demand-side in the new trading arrangements, both through supplier pressure and the direct involvement of customers, was seen by OFGEM as a particularly important development. The contractual freedom which is a feature of the new trading arrangements was expected to stimulate competition between suppliers and lead to more competitive buying of electricity, which in turn would put competitive pressure on generators. Thus the essential benefit of incorporating the demand-side would be to release the normal market forces opposing buyers' and sellers' interests.

In addition, OFGEM considered that the development of "two-sided" markets would reveal the latent responsiveness of demand, which under the Pool was treated in a highly aggregated manner assuming very little responsiveness. This could influence forward prices, but it also was anticipated that allowing demand responsiveness to emerge would provide NGC with another source of balancing services and hence enable it to balance the system at lower cost.

Customers with half-hourly meters were believed to be prime candidates to represent the demand side in formation of the new balancing services markets. But OFGEM believed that suppliers (acting as aggregators) might also play a role in realising latent demand side potential.

Under NETA, the demand side participation of half-hourly metered customers at the wholesale level has been limited to a small number of large commercial and industrial customers, for the provision of contracted ancillary services.

Table 15

Demand-side Contribution of Contracted Balancing Services – UK Wholesale Market

Service	2000/1	2001/2
Fast Reserve	0%	5%
Standing Reserve	23%	29%
Frequency Response	29%	29%

Contracts for ancillary services are shown in the table below, comparing the contribution that the demand side have made during the first year of NETA (2001/2) and the last year of the Pool (2000/01).

Whilst there has been little change in the percentage of frequency response services provided by the demand side under NETA, the demand-side has contributed a greater percentage of the reserve used by the system operator. This is particularly the case for fast reserve[68].

Prior to the introduction of NETA, no fast reserve was procured from the demand side. However, since September 2001, the system operator has held monthly tenders for the fast reserve service and from the outset the demand side has been successful in obtaining contracts. In recent tenders there have been new demand-side participants. As a result of increased competitive pressures, including from the demand-side, the average utilisation price paid by the system operator has decreased from £438/MWh in May 2001 to £118/MWh in May 2002.

The number of customers who can provide fast reserve is limited, but a much wider range of customers can provide standing reserve[69], since the timescales involved are not as onerous. Twenty-nine demand-sites, owned by eighteen different companies, participated in the annual tender for standing reserve in 2002.

The system operator continues to work with the demand-side to develop new balancing services that will enable suppliers to make use of the demand of their non-half hourly metered customers (up until now balancing services have only been provided by half-hourly metered customers). One example is the radio tele-switching of demand; the system operator is evaluating the use of agreements with three suppliers that will provide up to 1,500 MW residential remotely-controlled water heating load. This development could deliver a sizeable and distributed remote controlled demand capability, highly flexible in terms of location and quantity.

Demand-side providers have been actively encouraged to participate in the tendering processes and direct bilateral negotiations that NGC uses to

68. Fast Reserve – Rapid and reliable delivery of active power provided as an increased output from generation or a reduction in consumption from demand sources. Electricity supplied within 2 minutes at a rate of not less than 250 MW/min for a period of not less than 15 minutes.

69. Standing Reserve – As fast reserve, but with more flexible start-up periods, ramp rates and demand periods. The requirement is met by both synchronised and non-synchronised sources.

procure balancing services. In its procurement guidelines, the system operator specifically makes it clear that it was interested in procuring balancing services from demand side providers.

Beyond contracted ancillary services, however, there has been very little evidence of demand side participation. Within the Balancing Mechanism itself only 0.15% of the offers accepted by NGC have come from the demand-side. According to a recent market report[70] there are only two active sites participating directly in the Balancing Mechanism. Following the introduction of NETA there was some early evidence of the emergence of commercial contracts for load reduction between large customers and suppliers. However, in the presence of the post-NETA capacity increases and the consistently over-contracted market, prices have not risen to levels where these contract options have been called. As a result it is felt unlikely that the contracts will be renewed.

Demand Response Experiences – Retail

United Kingdom retail electricity has been a highly competitive market since the introduction of full customer choice in September 1998. The United Kingdom retail market model assumes designated load profiles for residential consumers[71] which are aggregated according to demand at a designated Grid Supply Point (GSP). A supplier is allocated a demand profile which is effectively the net of all meter-read volume, allocated according to a designated profile, plus all half hourly metered customers and unmetered loads (e.g. street lighting). These supplier totals are netted for the Grid Supply Point, profiled according the allocated usage profiles, with any differences effectively being distributed amongst common Grid Supply Point suppliers according to demand share. Under these conditions there is no incentive for a supplier to encourage a profiled customer to shift their consumption using price signalling. Under this so-called "difference-metering" mechanism, any load-shifting and subsequent economic gains of the actual consumption of an individual non half hourly metered retail consumer will be distributed amongst all common Grid Supply Point suppliers. Since there is virtually no half hourly metering at

70. Cornwall Consulting – Demand Side Participation under NETA June 2002.

71. UK Market has two domestic profiles – Domestic unrestricted (single rate) & Domestic Economy 7 (two rate).

the residential customer level in the United Kingdom, this market design failure has led to a dramatic reduction in the availability of price-response tariffs offered by suppliers.

However, despite the lack of real-time or time-of-use price offerings in the retail markets, the introduction of competition has achieved many of OFGEM's objectives in relation to end use price and customer choice. Two years after the introduction of competition in the domestic market, around 11 million (38%) of domestic customers have switched supplier at least once. Each week around 100,000 electricity customers are switching supplier, of these 56,000 in net terms are choosing to leave their former regional supplier, according to the latest OFGEM figures.

Recent research has revealed that the principle drivers of customer switching are.

Price

A desire to save money continues to be cited as the main reason for switching supplier, although there seems to be some weakening in its importance relative to other reasons such as dual fuel offers, the possibility of combined bills, a desire to obtain better services and switching following an approach by sales agents.

Dual Fuel

The ability to receive electricity and gas from the same supplier is now the second most important reason for switching supplier, with about 81% of customers who have switched now having the same supplier. Half of these have switched their gas supply to their existing electricity supplier. OFGEM has estimated that about 30% of all electricity customers are now on dual fuel deals.

Service Bundling

Rivalry between competing suppliers has been enhanced by the new marketing alliances that have developed with organisations outside the electricity industry such as high street retailers, banks and telecommunication companies. Some affinity deals, particularly with retailers, have had some success in gaining new customers, but in general they appear to have been less successful than had been expected.

Conclusions – England and Wales

England and Wales has a highly-developed liberalised electricity market, currently delivering lower prices with reductions of between 20-25% in the commercial and industrial sector and of around 8% in the residential sector, since its opening in October 1998. However, the demand side is poorly represented in the price determination process, since few retail consumers face prices that vary with the half-hourly wholesale price of electricity. Customers have little or no incentive to shift their electricity consumption away from peak periods or to consume less if they do not face half-hourly prices that reflect the real-time cost of purchasing wholesale electricity. This can have consequences for system reliability, may allow generators to exercise market power in the spot electricity market, and significantly reduce the likelihood that consumers will benefit in the long-term from electricity industry restructuring[72].

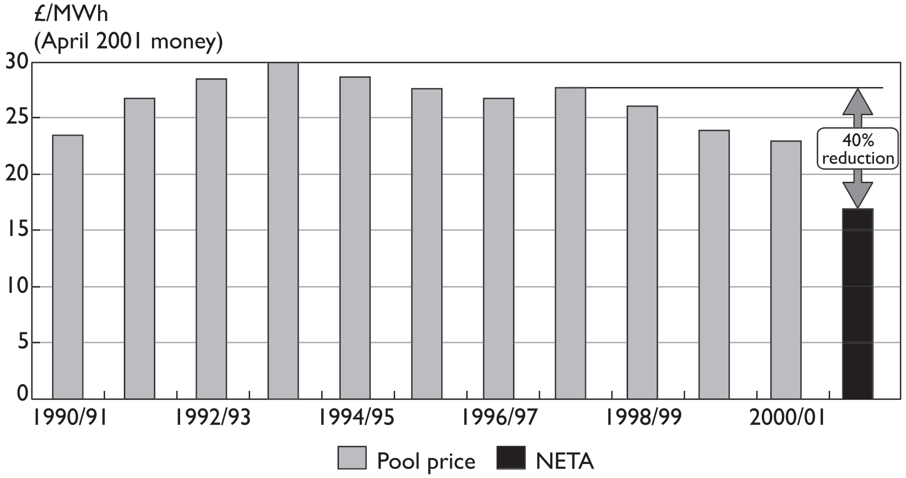
In the retail markets, despite expectations of innovation in retail pricing and the consequent formation of a market for Energy Service Companies (ESCOs), pricing remains relatively static and there has been little development or innovation in the provision of retail energy services. The basis for competition in electricity retailing is traditional discounted tariff structures, with differentiation being delivered in dual fuel, billing and customer service.

Demand-side participation in wholesale markets has been limited in scale and largely confined to the contracted ancillary services markets. The recent reductions in economic demand response in the wholesale market can in part be accounted for by overall spot price reductions seen in the market (Table 16), but mainly because the market is over-contracted for supply. This over-contracted position, made possible by over-capacity on the supply side, enables suppliers to minimize their imbalance risk and exposure to system buy-prices they would otherwise be exposed to. This condition in turn has reduced demand for balancing services and thus reduced the price-taking opportunities for to demand-side bidders participating in the wholesale market.

72. *Real-Time Pricing and Demand Side Participation in Restructured Electricity Markets – Patrick & Wolak July 2001.*

Table 16

Long-term Spot Price Trends



Absent constraint-based price signals from the system operator, the only commercial network load management instrument in effect is a form of maximum demand charging applied to commercial and industrial tariffs based on so-called Triad Periods[73]. This charging system may account for up to 500 MW of demand reduction during times system peak demand.

The potential remains for large customers to offer load management services to suppliers to assist them in managing their imbalance risk. However, discussions with larger customers suggest there is little evidence of such aggregation happening on a widespread basis.

The increased disaggregation of roles within the market design, whilst increasing the competitive environment, has also served to increase the complexity of participation for all buyers and sellers, but especially those sellers that are not well-established – those on the demand-side. The complexity of engagement for the development and delivery of new tariffs and pricing products is another notable barrier to growth in demand-side participation.

73. Both under the Pool and under NETA, Transmission Network Use of System charges are levied on the basis of a customer's average demand during the three Triad periods. This demand is defined as the average demand of a supplier over three half hours between November and February (inclusive) in a financial year comprising the half-hour of highest system demand peak and the two next highest half-hours of system peak demand, which are separated from the system peak and each other by at least 10 days.

If the full contribution of the demand-side to price formulation, reliability, security of supply side and mitigation of market concentration is to be realised, significant work will be required from both policy makers and market participants.

■ Key Conclusions – United Kingdom and Wales

Market Design

Whilst the market appears to have been designed with demand side participation in mind, many of the market rules harbour imperfections which require further attention, namely:

■ Licensing – Under current market rules only licensed suppliers (or licence exempt parties) are able to contract directly with the Balancing Mechanism.

■ Contract performance – Under current market rules demand-side participants have to forgo balancing services availability payments in order to participate in the Balancing Mechanism and are exposed to high price risk of System Buy Price for failure to perform, or to verify performance.

■ Technical Performance – Terms offered by the System Operator for the procurement of Balancing Services are often more suited to generation than demand. The minimum size requirements of 3 MW for frequency response and standing reserve and 50 MW for fast reserve, the ramp down and start up timing, and the lack of event duration information, effectively exclude many demand side participants. Additional technical barriers exist with regard to metering allocation between suppliers and load aggregators and more recently in the development of tele-switch load switching applications.

The reduction of the barriers mentioned above, coupled with an open and clearly-communicated economic opportunity for the demand side, would doubtless see the emergence of market aggregators and independent demand response service providers. Such aggregators would act as market accelerants, enabling economies of scale, streamlining of the commercial and technical requirements and removal of potential conflicts of interest between demand response service providers and energy suppliers.

Technology Policy

The wide-spread use of deemed load profiles within the residential sector, and the difference-metering process used to determine supplier demand, has led to a dramatic reduction in the potential for suppliers to offer innovation in retail pricing. Any move to more dynamic forms of pricing will require technology investments in metering and networks to support increased data and settlement information flows. It seems unlikely that any one supplier will invest in such technology to support innovation when the benefits of so-doing would be distributed amongst other suppliers sharing common grid access. The regulator should therefore commission research to further examine the effects of the current market design on the potential for increased innovation in retail pricing and the long term impacts of current retail pricing policies based upon pure price discounting.

Further, there would seem to be a case for the regulator to re-start activities on the potential contribution of advanced metering. Accurate and timely flows of consumer metering data have several key roles to play, roles which are all consistent with the stated aims of OFGEM. Advanced metering and data infrastructure would not only enable the introduction of more innovative tariff products, but would also provide information flows which will improve the performance of current change of supplier procedures, billing accuracy and improvements in customer services.

THE ROLE OF TECHNOLOGY

Technology has a key role to play in accessing demand resources. The cost, functionality and degree of process automation will be major determinants in the future growth of the demand response market capability.

Metering and communications equipment will enable the transfer of business-case-critical information – such as prices, load control signals, measurement, and data for settlements and billing – between contracted parties. Technology options for demand response can be broadly grouped into three classes:

- **Metering.** The meter remains the primary means of revenue measurement for the energy provider. Meter functionality will vary according to the application, the basic unit of recording being the watt-hour (typically kWh or MWh). Advanced metering may support additional measurement functionality such as the ability to store consumption according to time-periods, record and/or display instantaneous usage information such as watts, volt-amperes, reactive power, current, voltage and power factor.

- **Remote communication equipment.** A key need is to connect the metering and control equipment used by utilities, market operators, intermediaries and consumers. Remote communication may also include direct consumer communications equipment, using multiple user-friendly communication pathways to notify customers of load curtailment events.

- **Control equipment and software.** New technologies are providing higher degrees of process automation and control to designers of demand response programs. Air-conditioning cycling and heating control, remote load dispatch and advanced lighting control systems are serving to decrease the need for human intervention to respond to demand response price signals.

The use of these technologies to provide automated demand response at the residential level, enabling real-time response according to individual consumer price preferences, has been shown to have a marked effect on demand elasticity. In a recent United States study[74], advanced technologies delivering real-time pricing information and providing a degree of on-site automation for residential consumers, showed peak period usage reductions on weekdays during the hottest summer month averaged 26%, while reductions during critical price periods approached 50% during some hours. In addition, elasticities of substitution (between peak and off-peak periods) ranged from 0.20 to 0.33. These are among the highest values obtained in evaluations of previous residential time-of-use rates, showing evidence of strong customer price-responsiveness in the presence of enabling technologies.

Technology for Demand Response

■ Metering

The technology available from today's metering devices will play a key role in enabling many of the benefits of increased demand response. The traditional role of electricity meters has been to determine how much electricity consumers' use over a long time interval; in the case of demand response, a measurement is required to determine how much electricity use has been avoided or displaced over much shorter time intervals.

Traditionally, most small customers have been provided with a basic accumulation meter that provides a single consumption figure for the period between meter readings. The liberalisation of markets has seen the value of electricity captured in wholesale markets according to timed intervals, reflecting the true cost of marginal production according to such externalities as primary fuel cost, weather, and time of day. These timed intervals at the wholesale level represent the smallest unit of timed electricity that could be used for tariff or billing purposes. Support of tariffs which reflect this real-time price component, whether through time-of-use, real-time pricing or critical-peak-pricing tariffs, has placed increased demands on the metering device beyond its traditional energy billing function.

74. Residential TOU Price Response in the Presence of Interactive Communication Equipment – Stephen Braithwaite.

Minimum core functional requirements to enable the metering device to accommodate basic forms of price-response tariff require additional accumulating registers to record timed periods of consumption, such as peak and off-peak usage. In addition, a timing capability is required to determine start and stop times for the timed periods. This switching capability may be supplied by an internal clock device or by an external source via Radio (RF), Ripple Control (PLC) or Time-switch (clock).

Meters which support functionality beyond traditional accumulation of consumption are often referred to as Advanced Meters or Interval Meters. The highest resolution of consumption recording provided by Advanced Meters is so-called interval recording, whereby data is recorded to the timed interval, typically in 15, 30 or 60 minute periods. Consumption recorded period-by-period provides a complete daily profile per consumer. Once this data has been recorded, in addition to providing a level of data resolution able to support complex price response tariffs, the profile can also be used to determine changes to, or movements away from, the baseline consumption, often used to verify performance of curtailment programs.

■ Remote Communications[75]

Networks to support metering infrastructure are characterised as being either one-way or two-way in design. There are various design topologies delivering a range of functionalities, costs and benefits. Figure 6 below provides an indication of the different technical solutions implemented and available in the current market.

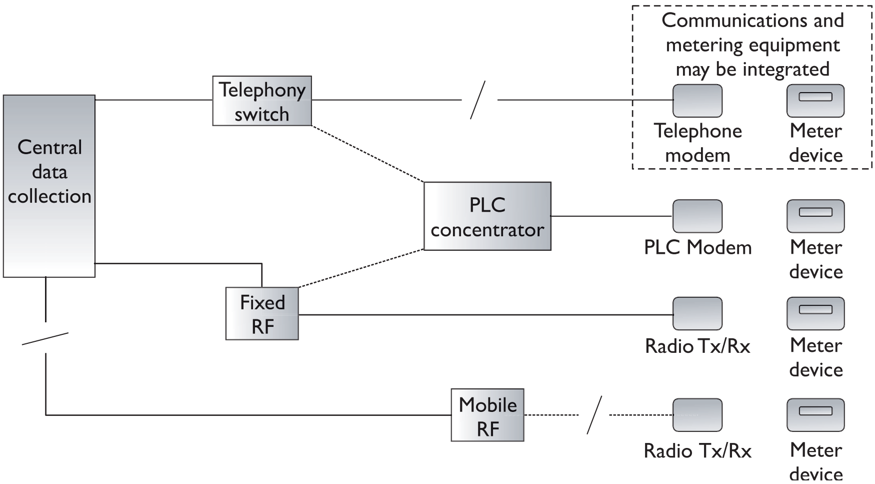
The design solution chosen will be governed by the application requirements and the meter reading environment. Geographic areas of high population density are typically required for fixed network infrastructure and for topologies which require data routers and concentrators. All the topologies shown above are able to support both one-way and two-way communications. One-way systems are often referred to as those that enable outgoing readings to be collected, although they can also indicate a one-way solution involving signalling a

75. IEA DSM Implementing Agreement – Interim Report on Customer/Utility Functional Needs and Communication Technologies – Prepared by Operating Agent Annex II January 1995.

price or rate change to the end customer. Full two-way communications refer to those systems that are able to both receive and send data.

Figure 6

Metering and Communication Topologies

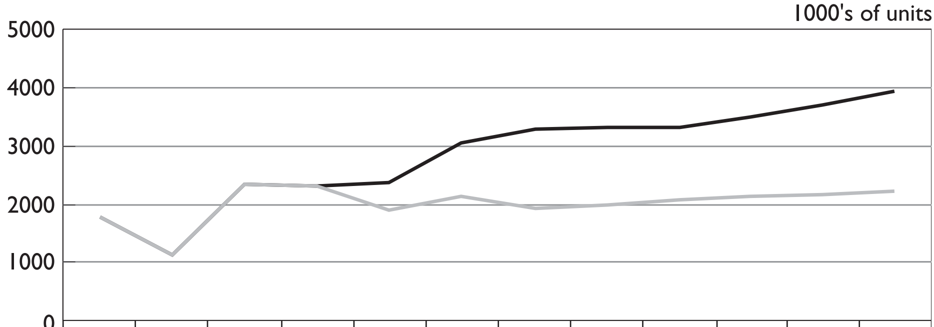


Automatic Meter Reading (AMR) has been the term traditionally used to represent metering solutions which incorporate a communications solution and whose prime function is to supplant manual meter reading. The acronym itself, which remains widely used within OECD markets, suggests that the real benefits of communications are directed to the meter reading function – principally for utility cost saving. Automatic Meter Reading technologies have achieved little penetration in most OECD liberalised markets, but have seen significant recent growth in the United States market as shown in Table 17. This is for the most part accounted for by the fact that the economic justification for Automatic Meter Reading investments was based upon obviating the need to manually read meters, and in the United States utilities read meters more frequently[76] than in many other OECD markets.

76. *Typically US utilities read meters once per month. In OECD Europe residential meters readings are often estimated and physically read for validation bi-annually and in some cases annually.*

Table 17

US AMR Shipments Forecast [77]



	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Optimistic Outlook	1757	1146	2320	2311	2375	3064	3308	3330	3319	3494	3703	3934
Current Outlook	1757	1146	2320	2311	1884	2130	1947	1988	2080	2124	2182	2248

The detailed study of the United States Automatic Meter Reading market illustrated above considers an optimistic outlook for growth of traditional Automatic Meter Reading contingent on:

- Federal tax incentives for technology investment will be included in a Federal energy bill.
- Utilities achieve expected improvements in their balance sheets.
- The technical success of pilot test either underway or planned within forecast period.
- Benefit analysis of pilot test either underway or planned within forecast period;
- SMD (Standard Market Design) is implemented by (Federal Energy Regulatory Commission (FERC).
- Higher wholesale electric prices.

77. *Source: North American Advanced Metering AMR: Unit Shipment Forecasts and Business Case Analysis for Electric Utilities (Frost & Sullivan, April 2003).*

Communication links and Automatic Meter Reading technologies provide the capability to automate and add value to traditional utility metering functions such as meter reading, field operations, billing and customer services. These same metering systems can provide customers with both the capability to interrogate and read meter information on demand, and to receive up-to-date energy pricing. More significantly, interval metering combined with integrated communications enables fully flexible information architecture capable of delivering a full range of demand response options[78].

A brief summary of the prevailing communications technologies is presented below:

Internet

The growth and availability of the Internet as a technology will probably have the greatest impact on the commercial viability of demand response technologies.

Systems are now available which enable the connection of consumers and aggregators with Independent System Operators and with retailers. The common language of the Internet and its ability to remotely serve applications will enable software suppliers to distribute control, measurement and settlements software directly through the consumers' browser.

Power Line Carrier (PLC)

Power Line Carrier systems used for utility applications are typically low bandwidth devices capable of utilising existing in-home wiring networks, providing two-way communications of metering and associated control data. Whilst the signalling technique has the advantage of not requiring the installation of a local area network (LAN), the wide area network (WAN) signalling between the host utility and the consumer does require access to the network infrastructure. Most metering commercial Power Line Carrier metering systems operate without using the high and medium voltage network for Wide Area Network Power Line Carrier

78. *Meter Scoping Study – California Energy Commission – Prepared By: Levy Associates.*

communications. Instead they use data concentrators connected to utility systems by means of remote telephony or existing utility communications infrastructure.

The Italian utility, Enel, is in the process of implementing what will be the world's largest Power Line Carrier remote metering reading application. The utility will install approximately 30 million Italian households with digital electricity meters, capable of being integrated into a complete home networking infrastructure. As of January 2003, there had been 6 million installations completed on the program, and by the end of 2003 this figure is expected to have reached 14 million. The project, which is estimated to cost €2.1 billion, will be completed in 2005.

As well as providing remote two-way communications, the system will support in-home communications, and appliance control and monitoring. The meters also provide functionality for remote meter reading and are capable of supporting full time-of-use tariffs.

The project will also allow Enel to monitor actual consumption in real-time, thus enabling more accurate load-forecasting, planning and electricity-contracting. The standard domestic default tariff is based on a peak load of 3 kW (premium 4.5 and 6 kW tariffs are also available) but currently Enel has no way of determining whether individual customers are exceeding that load (reportedly a widespread practice). The project therefore entails a certain amount of revenue protection on Enel's behalf.

Although it can be observed that Enel is making this investment in advance of full retail competition, it is claimed that the services offered by the metering will provide a robust infrastructure to support retail competition and specifically customer switching.

Telephone and Cellular

Telephony services have long been used as a means of remote collection of metering data, making use of existing infrastructure and commercial communication technology. The growth of telephony and cellular metering applications is linked to the commercial viability of network access provided by the local telephony operator. Some OECD telephony markets have developed specific tariffs for use by metering applications, which enable low-cost calling during defined timing windows.

There has been a recent growth in remote telephony applications including both cellular data calling and digital messaging. These systems typically have low bandwidths and relatively high costs, although they have the advantage of not requiring additional infrastructure investment beyond the metering end-point.

Telephony systems are traditionally one-way, whereby the reading agency will dial up the end device to collect metering data. Depending on the line-sharing arrangements of the local service provider, there are advanced metering devices that have the capability to dial out (initiate the call), functionality which can be used both to deliver meter readings and potentially to provide a confirmation of load reduction actions.

Radio Frequency (RF) – Fixed Network

The costs per point, or node, of fixed radio systems are dependant on a number of factors: the number of customers connected to the system; the geographic density of the customers; the topology of the area (which affects the propagation of the radio waves); and the location of meters (indoors vs. outdoors). Furthermore, fixed-radio networks are more economically-efficient when all (or almost all) the customers in a particular area are served by the same infrastructure. These radio systems are typically owned and operated by third-party vendors, which sell the service to utilities on a dollar-per-meter-month basis. The costs vary from about $1 to $5/meter-month, depending on the frequency of meter reading and the amount of data transferred[79].

Radio Frequency (RF) – Mobile / Drive-By

Drive-by metering systems use low-power radio signals to transmit meter data to walk-by or drive-by receivers. Such systems are used to reduce operational costs associated with meter reading. Radio modules can be either retrofitted to existing meters or installed into traditional electricity meters at manufacture.

■ Control Technologies

The function of the control equipment is to effect the necessary change in electricity consumption in response to a demand signal. In this role,

79. *Eskew 2000.*

control equipment is used to switch on and off the relevant electrical load to execute an agreed load reduction or to provide an automated consumer response to a pre-determined price threshold. The major differences between the various control products relate to the speed or notice required for switching, and whether the process control is manual or automatic.

In the case of rapid response, the control technology is usually fully automatic. For example, for frequency control, load is switched off when an automatic frequency relay detects a change in frequency of a fixed amount. Control to switch the process back on may also be automatic, or it may be manual, activated upon delivery of notification that the process can be restored. Advanced process control technologies may also be required to determine the optimal schedule of loads to deliver the agreed load reduction and still give satisfactory performance of the process.

Consumer control technologies represent the point of intervention between the end user and the demand response service provider. For larger industrial and commercial customers demand response event notification may be provided utilising existing pathways such as email, cellular telephone and paging devices[80].

The Business Case for Demand Response Technology

Support for time-variable consumption recording can be considered pre-requisite for all types of price-response tariff products. The potential contribution of time-recorded data is widespread and is limited to the benefits of demand response discussed here. If actual interval data were appropriately deployed[81] amongst market participants, including customers, multiple business opportunities would emerge:

80. Do "Enabling Technologies" Affect Customer Performance in Price-Responsive Load Programs? – Charles A. Goldman, Grayson Heffner Lawrence Berkeley National Laboratory, Michael Kintner-Meyer, Pacific Northwest National Laboratory.

81. Deployed data implies that real benefits of interval data recording are captured by deploying the data in a timely manner, consistent with billing and settlements requirements appropriate to price-response tariff products. This assumption may therefore include a requirement for advanced communication.

■ Customers Impacts

■ **Energy savings[82].** Demand elasticity of electricity will remain low while consumers are without access to the time-based value of their consumption behaviour. Consumers can save money by responding to price signals. The amount of saving will be determined by the benefits sharing contract position taken by the retail company. A recent United Kingdom study[83] has shown that the average consumer could save between 5-10% on an annual bill.

■ Supplier/Retailer Impacts

■ **Electricity pricing.** Interval meters would provide retailers with the capability and incentive to introduce more efficient pricing to customers. With interval meters retailers have the flexibility to better match the price offers that they make to customers to wholesale prices at which they purchase electricity.

■ **Billing.** The accuracy of wholesale market settlement between generators and retailers is increased if data from interval metering rather than from profiling is available and used in settlement. Interval meters have the potential to remove hidden cross-subsidies between customers, for example where simple averaged prices have been applied to all customers[84].

■ Market and Public Good Impacts

■ **Network management.** Detailed locational data concerning end use will enable more efficient pricing to network users of usage and system charges, reflecting more accurately the underlying costs of maintaining and operating a distributed and constrained electricity network.

■ **Capacity management.** Reduction in system peak loading resulting from widespread price response reduces the need for capacity to meet

82. UK DTI – Smart Meter Working Group Final Report.

83. "A Review of the energy efficiency and other benefits of advanced utility metering", by EA Technology for BEAMA and DEFRA.

84. Essential Services Commission (Australia) Installing Interval Meters For Electricity Customers – Costs And Benefits Position Paper – November 2002.

otherwise higher peak demands. The benefit arises from the avoided capacity cost in the generation, transmission and distribution systems where capacity increases are all driven by seasonal peak demands.

Furthermore, the addition of communications functionality to an interval meter greatly increases its capability to provide information and decision control to demand response market participants.

■ Impacts of Communications-enabled Metering

Where interval meter data is integrated into a communications network, significant additional benefits are delivered:

■ **Price signalling.** Basic communication functionality will enable true market price signalling in support of real-time pricing, time-of-use pricing and critical-peak-pricing programs.

■ **Meter reading.** Basic remote meter reading has been the traditional driver for investments in metering upgrades; remote meter communication will increase operational of data collection efficiencies (accuracy and timeliness) whilst simultaneously reducing meter reading labour costs.

■ **Customer service.** Remote access to customer usage information enables suppliers to resolve enquiries more efficiently.

■ **Billing and settlements processes.** Timely direct access to metering data will reduce billing errors, enable more flexible billing cycles and ensure accurate data are available for use in the management of customer-retailer transitions (customer-switching).

This suggests that there are multiple potential beneficiaries of the introduction of advanced metering, both public and private. However, the fact that the beneficiaries are split into many groups in itself presents the key barrier to deployment. In order for significant investment to be precipitated, the benefits must accrue in enough mass to one single party to allow the investment decision to be made. For example in the United States market, most state regulators require that investments in advanced automatic metering reading technologies are funded from utility earnings. In this case the customer benefits, which can be in excess of 50% of the net benefits[85], are not included in the utility investment decision. The outcome of this form of regulation is that the utility business case is severely undermined.

Thus in most OECD markets, despite the potential for more efficient markets that advanced metering offers, neither suppliers, retailers, consumers nor service companies have yet been able to develop the business models that would sustain wide-scale technology and infrastructure deployment.

This suggests that a fundamental change in regulatory thinking is required if advanced metering is to become widespread. Without regulatory attention to cost recovery policies and business models for technology investment, the traditional investor – the utility or distribution company – will continue to make decisions based only on the impacts to its own business case, and the full benefits of demand response will not be realised. The outcomes are evidenced by today's markets: metering continues to serve its traditional role of revenue capture and network management, and price-responsive demand growth remains inhibited by the lack of installed advanced metering and associated technologies.

Technology Applications

■ System and Transmission Operators

Transmission or systems operators at either the local retail level or the national transmission level are required to perform complex load-scheduling and dispatch functions to ensure the reliability and security of supply. In traditional electricity markets this process has been developed almost exclusively with supply-side resources, with a consequent focus on generation performance characteristics as illustrated in Table 18.

Direct consumer access to network markets for ancillary or congestion relief services is often effectively prevented by service requirements that have been designed for traditional supply side resources: a requirement

85. North American Advanced Metering AMR: Unit Shipment Forecasts and Business Case Analysis for Electric Utilities Frost & Sullivan April 2003.

for scaled loads, with system-operator-specified minimum contract positions often starting at around 5 MW of service capacity, and further standards set for such parameters as response time, ramp rates and minimum/maximum load cycles.

Table 18

Characteristics of Supply Side Resources

Reliability Resource	Traditional Supply Side Resources
Fast Reserve	Partially loaded thermal plant Hydro Electric (inc. Pumped Storage) Peaking Plant Renewables plant
Standing Reserve	Stand-by Generation (Uneconomical base load plant) Peaking Plant
Voltage / Frequency Response	Synchronous Generators / Compensators Capacitors and Inductors Transformers (Tap Changers and Voltage Boosters)

Dispatchable generator metering and communications equipment consistent with the resources shown in the table above will be specified to supply the Independent System Operator with output data in the order of seconds. This requirement is consistent with the security of supply objectives of the system operator, since the loss of one large generator must be compensated for immediately. It follows that since virtually all loads are small compared to generators, the statistical averaging across loads greatly reduces the need to closely monitor any one individual load.

To establish demand resources on an equal footing with supply side resources at the control desk of network operators would require high degrees of process – and technology-integration. In the United Kingdom, the National Grid Company typically issues in excess of 500 instructions a day to market participants to balance supply and demand on a second-by-second basis. Network operators often use technical standards and dispatch control technologies and software, which have been developed and refined over the course many years of market operation.

In this situation, only very large individual consumers will have the required resources to perform the necessary technology assessments and investments to enable direct participation in Independent System Operator markets. It therefore follows that the effective integration of smaller demand resources in the delivery of network operation services will only become feasible when an intermediary has a scale of aggregated response to justify such investments.

Whilst the emergence of such aggregators is feasible, it is becoming clear that there may not be enough "critical mass" representation from the demand-side to support and sustain such initiatives, at least without stronger incentives for such representation. Network operators may be willing to adapt and modify their control and technology requirements; however, greater demand will be required from consumers to drive such change. Regulators and public bodies should give consideration to the formation of research programs to consider the potential for increased demand side participation, and particularly to consider the potential to adapt Independent System Operator systems to specific demand-side practices and technical approaches.

Commercial and Industrial Technologies

Advanced metering is often a mandatory requirement for large commercial and industrial loads to enable, or make eligible, a load to participate in a demand response program. In part this is due to the need for accuracy in the amount and value of net demand reductions.

Direct load programs are typically those that require some form of signal sent from either the market operator or an intermediary to the demand resource, to request a demand side load reduction. The loads concerned will vary considerably by OECD markets, where heating and cooling load requirements in particular vary according to local climate and economic conditions. Detailed analysis of specific load types is a critical step in selecting technology according to the potential for demand reduction.

For larger commercial and industrial customers, utility interfaces are often centred on traditional Buildings Energy Management Systems (BEMS) and increasingly on internet-served energy management applications. BEMS technologies are implemented to provide in-building and process efficiencies and as such are synergistic with the objectives of both system-led and market-led response programs. Furthermore, as the potential for load control emerged as a market resource, a new market emerged for instantaneous power monitoring and recording, with low cost devices for on-site and load management being introduced. Under load participation programs, the requirements for accurate settlement and performance measurement has increased the accuracy and security requirements of these monitoring and measurement devices in order to match on-site control with billed or contracted data.

The emergence of the internet in OECD markets during the 1990s provided a significant spur to automation technologies, providing a stimulus to lighting, heating, cooling and motive power equipment manufacturers. Increasing standardisation of information exchanges, using XML and Microsoft Net standards, has provided increased opportunities for technology developers to connect consumers' loads to commercial and industrial BEMS and with utility control and billing systems.

■ Residential Technologies

Due to the relatively small amounts of energy and capacity involved at residential loads, installed technology is required to serve the consumer in a non-intrusive manner. For this reason technologies typically serve two primary applications:

- Delivery of real-time pricing/time-of-use functionality.
- Control of heating/cooling/lighting and other application loads (swimming pools, irrigation systems, etc).

Neither application requires automatic control, although residential demand response programs on offer today are able to deliver this if required.

A good example of how a mix of complementary technologies can be utilised to deliver a real-time pricing program is provided by Electricité de France's (EDF) "Tempo" program, which has been in place since 1996. This program features two daily pricing periods, on-peak and off-peak, and a day of-the-year pricing arrangement. It can be considered as a form of critical-peak-pricing. The year is divided into three day-types, each consisting of a high and a low rate, as illustrated in the table below.

Table 19

Tempo Tariff Structure[86]

Service	9 KVA	12-18 KVA	24-30 KVA	36 KVA
Standard Subscription	€134,76	€184,56	€339,48	€456,12

Day Type	Low Rate Charge	High Rate Charge	No of Events
Blue (Low)	3.35 c/kWh	4.15 c/kWh	300
White (Medium)	6.77 c/kWh	8.01 c/kWh	43
Red (High)	12.50 c/kWh	34.87 c/kWh	22

EDF does not offer a fixed calendar of days, but customers can check what pricing colour will take effect the next day in a number of different ways:

- Consulting the Tempo Internet website[87].
- Subscribing to an email service that alerts them of the colours to come.
- Using Minitel (a data terminal particular to France, sometimes called a primitive form of Internet).
- Subscribing to a telephone dial-up notification service.
- Checking an electrical device (compteur electronique) provided by EDF that can be plugged into any electrical socket.

The Tempo rate was preceded by a pilot program, in which prices were quite a bit higher than those that were ultimately implemented. The pilot program yielded price elasticities of – 0.79 for on-peak usage and – 0.18 for off-peak usage[88]. There was no significant variation in elasticities across day types. On-peak usage and off-peak usage were determined to be substitutes, but the estimated cross-price elasticities were small. In absolute terms, the value for the on-peak elasticity was substantially higher than values found in the United States. However, the value is

86. Source http://www.tempo.fr – (Price are current as of May 2003, are shown for illustration purposes only and do not include regional or municipal tax).

87. http://www.tempo.tm.fr/

88. Aubin et al. (1995).

similar to estimates for Swiss households: a short-run own-price elasticity of – 0.6 during the on-peak period and – 0.79 during the off-peak period[89].

Another example which features increased automation is a WAN/LAN solution offered in the United States as part of the Gulf Power Advanced Energy Management Goodcents® Select program (AEM). To participate, customers must take service under the Residential Variable Service Program rate (RVSP), a form of critical-peak-pricing. There are four daily rating periods and rates – Low, Medium, High, and Critical[90] as illustrated in the table below. For the Low, Medium, and High rating periods, both the times and rates are set by tariff[91]. For the Critical period, only the rate is set; the times at which it occurs depend upon circumstances in the wholesale market.

The standard tariff for non participants has the customer charge of $8.07/month and a flat energy rate of $0.057/kWh.

Table 20

*Gulf Power Goodcents® Select Tariff Structure**

Service	Charge
Standard Customer Charge	$8.07/ month
RVSP Participation Charge	$4.54/month

Rate	Charge	Percent of Annual Hours in Effect
Low	$0.035/kWh	27%
Medium	$0.046/kWh	53%
High	$0.094/kWh	19%
Critical	$0.290/kWh	1%

* These prices were current as of May 2003 and are for illustration purposes only.

89. *Filippini (1995).*

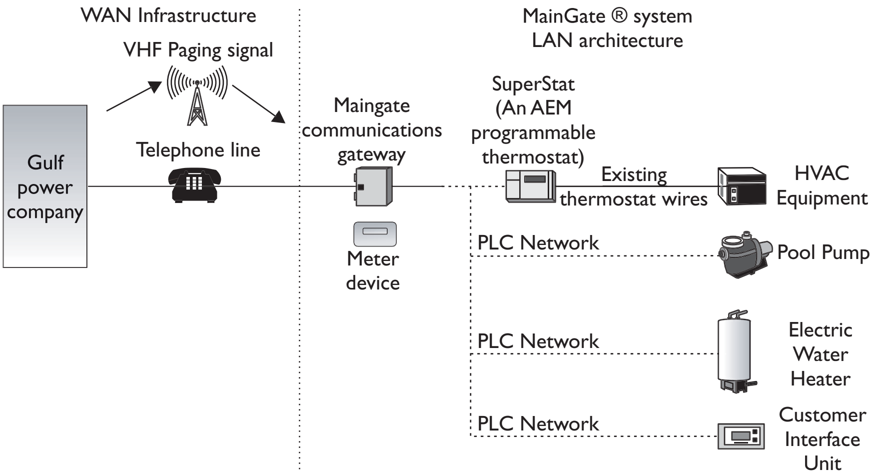
90. *Critical periods are most likely to occur Monday-Friday between 6:00 am and 10:00 am in the winter and between 3:00 pm and 6:00 pm in the summer.*

91. *The hours of the high and medium periods differ seasonally (winter and summer).*

The Advanced Energy Management program architecture (Figure 7) comprises of a Maingate® System local area network which is used to receive pricing signals, to alert the consumer and to automate control of end uses according to pre-programmed customer preferences. The wide area network comprises of a switched telephone uplink, to retrieve billing information, and a Very High Frequency (VHF) paging link which is used to transmit pricing signals to the consumer and the LAN.

Figure 7

Residential Automation for Real-time Pricing



The degree of automation offered enables customers to control their energy usage by programming their cooling and heating systems, water heating and pool pumps to automatically respond to varying prices consistent with their price/comfort thresholds.

Diversified summer load reductions have averaged 2.10 kW per house in the summer and 2.73 kW per house in the winter. Load reductions during critical peak periods were, on average, 44% during critical price periods, 21% during the high price periods and 5.9% in the low price period. Consumption increases in the low rate period averaged 11%. Program results have shown that the use of this form of price response yields both load-reduction (conservation) and load-shifting benefits. Of the resultant average annual bill saving of $187, 57% is attributable to saved energy and the balance accounted for by load-shifting. This confirms earlier results suggesting that demand response programs may have a significant energy conservation impact.

The Advanced Energy Management program is a useful example to illustrate the role of the in-home gateway[92]. The gateway in this architecture is specifically implemented to support the energy management application. There are multiple international home automation standards in use across IEA markets, with X10, Bluetooth, CEBus, Lonworks, Batibus and European Home System in widespread use today. The growth of installed home automation systems[93] means energy management program designers now have greater opportunities to piggy-back communications and data needs onto other application infrastructure, such as security, home comfort and monitoring, thus increasing the cost efficiencies of both applications.

The Tempo and AEM programs also well illustrate that there are multiple technology pathways open to utilities in implementing technologies to support real-time-pricing. Furthermore, both programs have delivered high degrees of elasticity in consumer responses and conservation impacts. It is significant to note that there are many such trials in operation in electricity markets and yet, with the notable exception of the ENEL program, few have yet accessed the scale economies that would come with mass deployment.

Technology Policy Issues

■ Technology Ownership

At the heart of the debate over the deployment of demand response technologies lies the question of who should own and invest in the technologies.

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92. The home gateway will serve two primary purposes: as a hub to connect and manage the intelligent appliances in the home and as a communications gateway between the home and the outside world.

93. 20% compound growth rate of installed systems from 2003-2009 – Frost and Sullivan – European Home Automation Market Feb 2003.

Liberalised markets have introduced multiple stakeholders into the business of electricity supply and demand. As a result, identifying the party who is best able to capture the critical mass of economic benefits, sufficient to enable the necessary investment decisions, is now a more complicated task. In the United States, New York State has provided assistance to technology investment with the support of public funding through New York State Energy Research and Development Authority. The agency provides up to 50% of funding support to technology investments which include metering and demand response automation.

In Australia, the Council of Australian Governments (COAG) review of energy markets has concluded that to gain the possible benefits of demand management, price signalling to all customers is essential. The report states, "A mandatory rollout of interval meters to all customers is necessary to achieve the full benefits for all consumers of electricity market reform"[94].

These examples support the view that, given the spillover benefits in the public domain, government or public agencies should remain party to the investment paradigm in some way.

■ Competitive Metering Services

A number of OECD countries have moved towards broader models of competition, in some cases including the opening up of metering services markets. The monopolistic and embedded nature of the metering functions, historically a service performed by the incumbent energy service provider, has presented market designers with significant institutional, cultural and technological barriers in pursuit of competition objectives.

In the traditional billing context, there are a variety of discrete metering services required to maintain an operational billing service, namely:

- Device ownership – Lease or buy provisions.
- Field services – Installation, removal and maintenance.
- Meter reading – Data retrieval, data validation and data processing.
- Customer services – Billing.

94. *COAG Energy Market Review, Draft Report, "Towards a Truly National and Efficient Energy Market", November 2002.*

In the United Kingdom and in some United States market models, these functions have been separated into discrete competitive services. While this may have the effect of enabling the introduction of competition, it also serves to disaggregate further the responsibility for technology deployment. This separation has the corollary effect of limiting the potential for technology investments which might benefit the wider value chain of meter reading, data collection, billing and customer service.

In addition new technology investment is often required to facilitate and streamline the additional interfaces between these new metering services activities. Policy makers should review the growth in technology investment in each of these new metering service sectors; disproportionate investments focussed solely on the operation of the new service segment interfaces will act as an early indicator that efficiencies may be being forgone (for the sake of competition).

Stranded Assets

There are two prevailing concerns relating to stranded assets relevant to the consideration of new technology investments. The first relates to the risks associated with investment in new metering technologies and infrastructure. Where demand response investments are made in the context of a private market opportunity, the prime source of risk comes from the effective determination of the useful, or working life, of the asset or investment. In the pre-liberalised electricity market, the relatively stable price environment enabled regulators to develop long-term cost recovery mechanisms, which were able to assume an economic life for technology assets. In some cases, this was up to 20 years. For the investor post-liberalisation, the risk is increased by the limited security of contracts over which to amortise such an investment. There is also the risk that the demand response product may be withdrawn or modified in a way which undermines the investment. Prime sources of such risk include changes in price regulation or market design which impact on wholesale market price levels. The outcome has been that basic traditional investments in basic metering technologies have continued, whereas investments in advanced enabling technology have not occurred to any significant extent.

The second stranded asset concern relates to the displacement of existing technology stock. Most research indicates that the benefits of technology deployment are more likely to be captured and equitably distributed in the event of rapid and widespread deployment. However, this implementation solution must account for the displacement of the existing metering stock. In most cases existing stock will be on the balance sheet of the owning utility company for periods of up to 20 years. Thus any form of mandated replacement policy will potentially require substantial asset write-downs. Potential steps to mitigate the economic impact to the existing asset holder may include:

- Retrofit technologies which utilise the existing asset base.
- Asset resale (reselling displaced assets into secondary markets).
- Managed swap-out programs (phased replacement / older meters first).
- Early adoption of new build policies (ground-up deployment).

Technology Standards[95]

The development and application of metering and communications standards will greatly enhance the opportunities and value of wide-scale metering technology deployments. When appropriate and market-ready metering standards are selected and applied, metering investors will be well-positioned to capture the benefits set out below.

■ Multiple Sourcing

Standardised interfaces allow investors to purchase equipment from multiple suppliers. The ability to access multiple sources offers investors several additional benefits. First, investors can seek the supplier with the lowest price, since interchangeable equipment can be connected on either side of a standardised interface. Second, investors can protect themselves against the risk of a manufacturer dropping support for

95. IEA DSM Implementing Agreement – International Standards Activity in Customer/Utility Communications for Demand Side Management and Related Functions Interim Report Prepared by Operating Agent Annex II April 1996.

equipment or going out of business. Finally, multiple sourcing creates a competitive supply environment, which in turn stimulates competitive technical and commercial enhancements.

■ Cost Reduction

Equipment manufacturers who are competing for product supply, irrespective of their differentiation strategy, will need to maintain downward pressure on costs in order to remain competitive. Common standards will also serve to improve efficiencies in the supply chain to the manufacturers, reducing the occurrence of low volume, high cost customised product components.

In addition, the investor company will require less specific product – and systems-training to support the meter and associated devices, and may be required to carry fewer inventories to support the installed base.

■ Inter-operability

Standardised interfaces greatly enhance the inter-operability of automated utility systems. Interoperability implies two very different capabilities: firstly the inter-operability of similar pieces of equipment; secondly the inter-operability of different kinds of systems.

Inter-operability of similar pieces of equipment means that units designed to do the same functions can be used interchangeably. Standards for metering to provide an output in the form of an energy weighted pulse are an example of this. Standard pulsed outputs are in common use and can be used as an input to a retrofit or add-on device, capable of more sophisticated functions, such as time-of-use tariff and automated metering reading solutions. The benefit of this approach is that the more functional component of the metering solution, the add-on device, may be upgraded or replaced at some point in the future without the need to replace the base meter.

The second meaning of inter-operable equipment refers to interfaces presented at the output of the metering network and its systems. It is important that data gathered by the metering system be transportable from the initial metering application to other utility applications, such as customer services and planning. For example, the designer of a network modelling system could insert real-time load data gathered by a metering system into the input parameters of a network model.

■ Migration Strategy

Standardised interfaces facilitate the orderly migration of automation systems from any initial configuration and mix of systems to a completely integrated system. One simple example of a migration strategy would be to replace all previously-installed automated systems with new equipment. This generally may not be an optimum strategy, since the utility would be discarding a significant amount of still-useable equipment. An alternative strategy would be to begin purchasing all new equipment with standardised interfaces. Legacy equipment near the end of its life could be replaced when it wears out. When it is necessary to link recently installed legacy equipment, the utility would supply a "translator" that interfaces the legacy equipment to the new standard interface.

■ Reduced Obsolescence Risk

A constant barrier to the deployment of advanced metering technologies is the challenge of ensuring the investment is not rendered obsolete before it has served its functional and economic lifetime.

Obsolescence can occur when manufacturers cease trading, withdraw products or when technology is superseded by more functional models. The use of open performance standards to ensure functionality according to business model and operational needs can serve to mitigate these risks to some extent.

Technology Costs

The perception or reality of high costs for demand response technologies has been an important barrier to the acceptability of demand response to regulators. However, technology costs can only be gauged relative to the economic benefits delivered, or in business terms, to the incremental revenue which comes about when an investment is made. In the complex electricity markets of today it is the determination and maximising of this incremental value that remains the greatest challenge. Without agreement on a business case value it is not possible to determine whether technology costs are prohibitive or otherwise. In this sense, a review of technology costs will remain somewhat arbitrary; figures presented here are for reference and as a guide only.

A crucial recent development in demand response markets has been the introduction of the so-called "demand response business case". The purpose of developing a business case for demand response is to establish a commercial value for the demand transfer in question. The value created will yield a baseline against which investments, or costs, can be efficiently evaluated. In the absence of individual business case illustrations, which are highly specific to market structures, prices and clients, the costs illustrated below become anecdotal. That is not to say that they are unreasonable estimates; rather, it is to say that viewed in isolation they cannot be considered as either too high or too low to be justified.

Table 21

Basic and Advanced Meter and Installation Costs – Scale Effects

	Replacement		Mass Deployment[96]	
	Residential	**Industrial**	**Residential**	**Industrial**
Basic Meter	\$20-25	\$150-200	\$15-20	\$100-150
Advanced Meter	\$80-100	\$175-200	\$30-55	\$150-175
Meter Installation	\$50	\$150	\$25	\$100

Set against the cost profiles illustrated above, there are three tiers of cost modelling in use today:

■ **Least-cost model.** This method considers only the basic requirement to yield an energy meter reading, and pursues the least-cost path to deliver it. This type of cost model is supported by regulation, in the form of cost-recovery mechanisms, in pre-liberalised markets.

■ **Automated Meter Reading (AMR) model.** The Automatic Meter Reading model is in widespread use with the United States market. The

96. *Mass deployment assumes an program in excess of 250,000 devices.*

model recognises the incremental benefits of remote communications with the metering device through the reduced labour-based costs of meter reading, field service, customer care and of improvements to the billing cycle.

- **Enhanced Revenue model.** This model is often used as an adjunct to the Automatic Meter Reading model. This model is used by utilities (the traditional investor) to assess the potential impacts of advanced technologies including demand response capabilities. The impact of such models is highly dependent on the nature of the local market. Markets which are capacity or network constrained will yield significantly higher benefits than those which are not.

Each model chosen will be further subject to the capital depreciation term, or the allowed cost recovery period if applicable. Least-cost models usually assume terms of the order of 20 years. Depreciation terms for the Automatic Meter Reading and Enhanced Revenue models may involve commercial decisions on the part of the investor, driven by access to utility funds and regulated cost recovery mechanisms.

Evaluating Demand Response Programs

Measurement of demand response program performance is an important and necessary step in the incorporation of demand resources into a well-functioning electricity market. Objective evaluation will provide critical insights to the future development of demand response capabilities and will help to guide technology investment priorities.

Performance evaluation should focus on the measurement of pre-demand response and post-demand response outcomes. The extent to which demand response program will deliver on the range of potential benefits will be a function of the program design, target customer segment and deployed technology. At a minimum, evaluation should consider the following potential impacts:

- **Market price impacts[97].** Wholesale and retail market prices.

97. *Quantifying price impacts involves simulating what prices would have been had the curtailments not been undertaken.*

- **Customer impacts.** Customer economic benefits and business case, customer well-being, customer satisfaction.
- **Participation.** Program self-selection, drop-out rates, free-rider issues, program marketing.
- **Public good impacts.** Reliability, security, environmental.

Measuring Demand Response

The measurement of time-variant demand response is achieved by the use of metering equipped with multiple time-switched storage registers[98]. This method of measurement is used for most forms of dynamic pricing tariff, where the consumer receives payments in the form of rate discounts, against consumption made during the less expensive time periods.

In the case of buy-back, or curtailment programs, an absolute measurement is required for demand response performance: consumers are contracted and will be paid according to a specific amount of load reduction. The actual amount and timing of the reduction forms the basis for payment. For this reason advanced techniques have been developed for determining the curtailment performance.

Actual load reduction is calculated as the difference between an agreed normal level of consumption, known as a customer baseline, and the actual metered load in each interval (Figure 8). The baseline is the “estimate” of what the load would have been under normalised conditions, absent demand response. The process involves establishing an agreed algorithm for typical load consumption on a specific day type in advance. This step would typically account for a consumption profile on an equivalent day, a weekday, weekend or holiday, averaged over a period and compensated for weather effects. During a response event the actual load consumption is metered and subtracted from the agreed baseline, yielded the quantity of demand response then used for billing and payment.

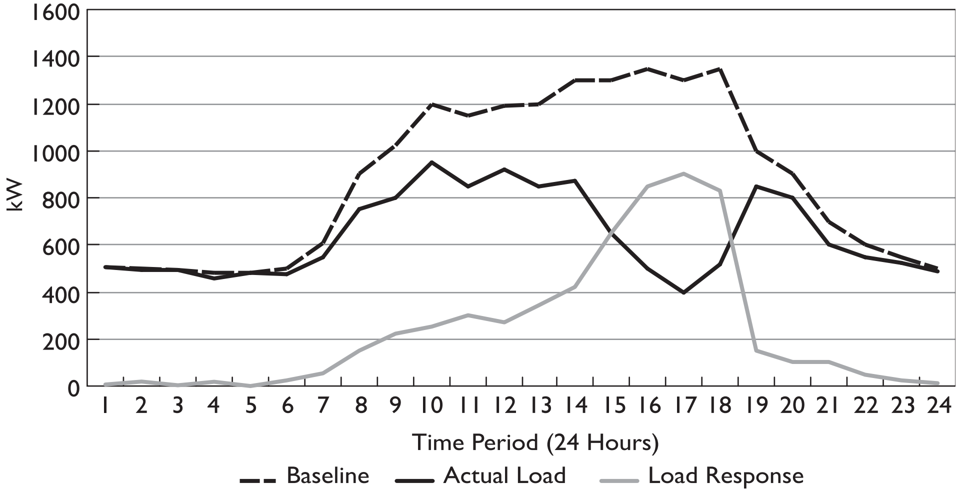
This process implies that the consumer load is in some way stable and predictable within acceptable limits. It is necessary for most customer

98. *Ibid., p. 104.*

baseline programs to verify periodically that no major changes have occurred to the customers' facilities or processes that would necessitate new baselines being calculated.

Figure 8

Baseline Calculation of Demand Response



Markets have adopted various approaches to baseline calculation, but there are some common component building blocks to most approaches:

- **Load classification.** An initial step is to classify customer loads according to the potential for reduction. Load may be characterised by weather-sensitive end uses, such as heating and cooling, versus those that are less sensitive such as industrial process and facilities.
- **Data selection.** Determining which historical consumption data will be valid for inclusion in the agreed baseline. Selection will need to recognise typical load conditions for days preceding the demand response event. Typical approaches include the use of data from the last 10 to 20 normal days, days during which no demand response event was called; from a subset of the last 10 to 20 normal days during which peak loading occurred; from a full season of data.
- **Estimation method.** The method applied to the selected data that estimates the provisional baseline for the demand response period event.

Typical approaches include averaging the load for the selected intervals over the sample set and the application of some form of weather-based compensation factor.

- **Adjustment method.** The method of fine-tuning the estimated baseline to account for observed variations immediately preceding or during the event. Often this involves an additive or multiplicative adjustment in the event of a significant variation between estimated baseline load and actual or observed load, in the hours immediately preceding the event.

Impacts on Utility IT Systems

Competitive markets create a significant incremental burden on the existing utility IT infrastructure. In addition to the matters of customer registration and advanced processes to support customer migration, expectations of customer service will also increase proportionally. The resultant technology infrastructure performance requirements for metering, billing and customer service IT will thus increase significantly.

This need for additional IT horse-power will be further increased as utilities strive to determine the end-use price of consumption (per customer), set against a complex trading and contracting supply market. It cannot be overstated how important it is for utilities to employ IT solutions which enable a complete understanding of the cost to serve individual consumer types. Such segmentation data will become increasingly important in the maintenance of retail margins and to support marketing and pricing strategies in the next phase of retail market evolution. At even the most basic operational level, absent price regulation, utilities will require advances in IT infrastructure to deal with the increased complexity of determining end-user pricing.

Whilst the principles of operating large complex billing and Customer Information Systems (CISs) may seem routine, the complexities of routinely delivering timely and accurate bills, to hundreds of thousands of consumers, is a formidable task. Even prior to liberalisation, larger commercial and industrial customers had supported several consulting and service firms whose business is bill checking. The volume of high-cost mistakes and ultimate corrections in favour of the customer suggest that the process of computing and rendering a bill is not easily accomplished. During the transition to competitive retail markets, where start-of-contract and end-of-contract readings must routinely be exchanged between suppliers, problems have already developed.

Recently in the United Kingdom, the electricity consumer watchdog, Energywatch, estimated that some half a million customers have problems with their energy bills. Research carried out for Energywatch reveals that over the last few years up to two million people have faced financial difficulties because of inaccurate gas and electricity bills. Absent the significant IT investment, these market failures will be difficult to correct.

Problems can be traced back to the utilities' first implementations of billing and Customer Information Systems. The earliest systems were designed to support simple billing and customer records (i.e. name, address, telephone number) and little else. However, due to limitations in early computer system hardware, almost all Customer Information System designs employed a monolithic, rather than modular, design. Such a design worked well for simple basic tariff billing and customer contact management. However, since the late 1970s utiliity systems have entered a stage of almost continuous modification to accommodate much more complex time varying, demand, and other incentive type rates.

The design and relative complexity of modern real-time-pricing and dynamic-price programs are now stretching these earliest Customer Information Systems to breaking point. In many cases, utility program designers are faced with the task of designing programs that are compatible with the capabilities of the installed Systems. If the embedded Customer Information System cannot be modified or upgraded to accommodate a program design, then the program will not be implemented.

These are not the only challenges faced by modern billing and Customer Information systems. In addition to functionality to support dynamic pricing, utility Customer Information Systems may be required to support:

- Loyalty / reward programs;

- Multi-fuel products;
- Cross-channel marketing opportunities;
- Internet/online billing.

Despite these implementation challenges, the potential rewards of a comprehensive consumer-to-utility information technology solution, capable of capturing frequent and complex consumption data, could be significant. Real-time flows of consumer information into advanced Customer Information Systems would provide multiple benefits:

- Fully-enabled retail marketing (segmentation, pricing, cross channel);
- Detailed demand side information for contract risk balancing;
- Reduced billing and customer service errors.

Within the utility organisation, retail product designers should maintain close connections with Customer Information System and IT support organisations to ensure that, wherever possible, the complex functionality required to support dynamic pricing is accessible when needed.

REGULATION AND POLICY MEASURES

It was expected that the liberalised market would deliver increased innovation in the retail pricing options and that, for example, new Energy Service Companies (ESCOs) would emerge at the retail end of the market.

In many OECD electricity markets this has not happened. Consumers have been free to choose: to choose a lower price; to choose a bundled product; or to choose a new billing or customer service offering. However, energy services and energy efficiency have yet to take their place on the landscape of retail offerings and therefore in the minds of electricity consumers.

To a large extent, the determining factor is the structure of incentives created under the liberalised market design. The case study illustrated below, followed by the policy options discussion, highlights several of these key policy and market design impacts.

Policy in Action

The time-of-use rate offered by Puget Sound Energy (PSE, Washington, United States) was considered by many to be one of the finest examples of time-variable retail pricing operating in the United States liberalised electricity market. Despite this, the program ceased operating in November 2002.

The program, known as Personal Energy Management (PEM), featured a four-tier time-of-use tariff offering an economy rate (Mon-Sat 9 pm-6 am / Sunday and Holidays), a morning rate (Mon-Sat 6 am-10 am), a midday rate (Mon-Sat 10 am-5 pm) and an evening rate (Mon-Sat 5 pm-9 pm).

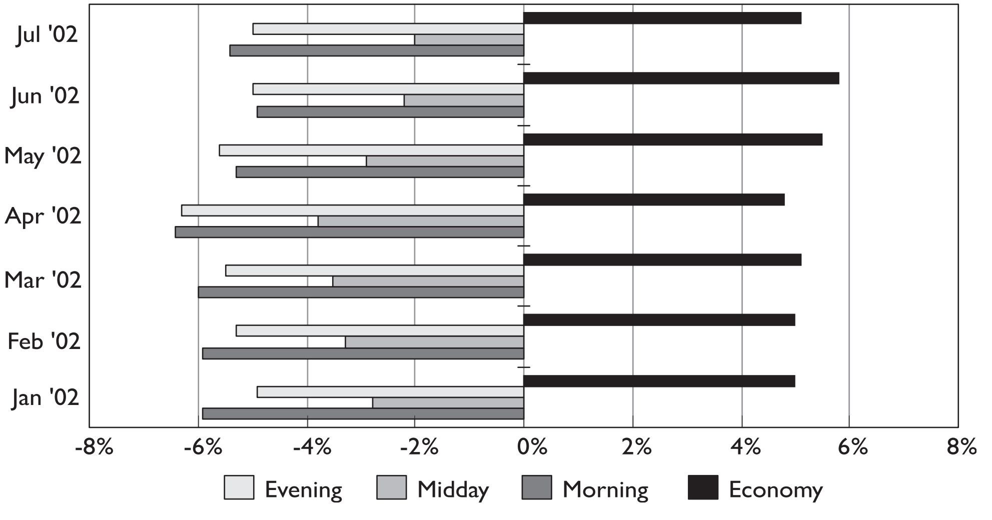
The program was enabled by an advanced metering infrastructure which supplied both the utility and the consumer with detailed consumption information. The data was collected, processed and transmitted daily to the utility's Customer information system (CIS). Newly-developed CIS applications took that information, matched it with the tariff price at the time of usage, and then provided the information back to customers using internet accounts and mailings, making it possible for them to make informed usage decisions.

Following rate approval by the state regulator, PSE placed 330,000 residential consumers on the time-of-use tariff and included an opt-out provision for consumers who chose not to participate. During the first year of operation the opt-out rate was a less than 1%.

PSE customers responded well to these new services. In a participants' survey conducted by PSE, 91% of residential customers took actions[99] to alter their energy use, of which 89% shifted the time at which they used electricity and 49% reduced their usage in direct response to variable pricing[100]. Figures 9 and 10 below illustrate the load shifting and reduction impacts of the participating residential customers.

Figure 9

PSE PEM Residential Load Shifting Impacts[101]



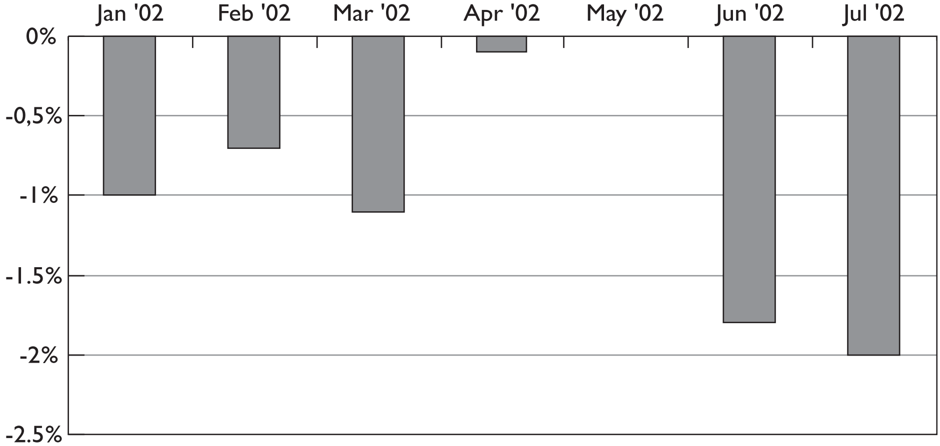
99. In addition to load reduction and shifting, other actions included the purchase of more energy efficient equipment, improving property insulation and increased use of back-up heat.

100. Proceedings – California Experiential Workshop Presented by Puget Sound Energy – Brian Pollom and Todd Starnes – September, 2002.

101. Source: Brattle Group.

Figure 10

PSE PEM Residential Load Conservation Impacts[101]



Despite the clear emergence of demand response on the part of the consumers, the anticipated bill savings failed to emerge. With realised bill savings of between $1-2 per month for highly responsive consumers and the subsequent application of an additional charge (in July 2002) for incremental costs of metering reading of $1 per month, the potential for economic gain on the part of customers was severely restricted. It was in light of these economic outcomes that the state regulator and PSE chose to terminate the program[102].

To the extent that the program demonstrated customers' willingness and ability to respond to price signals, it can be considered a success. While this is not documented, it must be supposed that the successful demand response enabled PSE to realise savings in their wholesale electricity purchases. However, the failure of the pricing structure to deliver sufficient economic benefit to the consumer, reflecting and valuing their behavioural changes, resulted in the premature program termination and considerable negative media reporting.

102. Under the terms of the settlement, the program became an opt-in program for new customers. The peak/off-peak rate differential of the TOU rate was reduced. A monthly fee of $1 a month was levied on participating customers. Finally, each quarter PSE would notify customers of their savings (or losses) on the program, and it would switch all customers to the lower-cost rate (flat or TOU) in August 2003.

■ Policy Environment

In a regulated retail environment it is the responsibility of both the regulator and the utility to ensure that the demand response behavioural changes are reflected in equitable financial savings for the consumer. Furthermore the regulator has additional responsibilities to ensure the offer does not:

- Disadvantage non-participating customers;
- Provide undue economic advantage to the utility; or
- Conflict with existing energy efficiency objectives.

On the part of the utility, the business case for the necessary investment in program design, implementation and operation must also provide an equitable return for customers.

PSE's program design was intended to enable better pass-through of the marginal cost of electricity on the wholesale market to the retail market, and thus to increase overall market efficiency. However, the regulatory environment in which the program prices are set is not conducive to a sufficiently rapid reaction able to reflect the potential volatility of wholesale markets. At the time when the program was introduced, May 2001, during the western states' power crisis, wholesale markets were characterised by extreme price volatility and a near-total absence of demand response. Against a background of such extreme pricing, during the first year of the program's operation, over 55% of residential customers experienced bill savings. However, during 2002, under the terms of the final time-of-use rate offered and with wholesale markets more stable, PSE determined that 94% of customers remaining on the time-of-use program were paying higher electric bills than they would have paid if they had opted out of the program.

In the course of the regulatory approval for this program, a final noteworthy policy development was the application of the time-of-use tariff on a mandatory basis with an opt-out option, as opposed to a voluntary, opt-in basis. Consumer and regulatory acceptance of this measure was implicitly contingent upon the implemented rate being revenue-neutral for those consumers who chose not to alter their consumption behaviour. In the presence of more volatile wholesale markets, this form of price regulation is in effect maintaining an insurance cost premium, insulating non-responsive consumers from the impacts of their usage. During times of increased volatility, this premium will become more valuable and should not be borne by the customers who have evidenced their willingness to provide a natural, market-based demand response.

Finally, the mandatory program application, across a large residential retail base, would have had significant impact in enabling access to scale economies in program design, implementation and operation.

Remedial Policy Options

Based on this experience, several remedial policy measures are suggested:

- Increase the use of multiple-pricing pilots to further develop statistical evidence of retail market price response elasticities;
- Utilise information provided to analyse impacts against alternative wholesale market scenarios (low/high marginal cost, volatile/emergency costs);
- Review and streamline retail price-setting procedures to decrease time-to-market of new tariff designs;
- Require detailed declarations to the regulator of earnings and benefit-sharing impacts by those utilities offering time variable pricing; and
- Re-evaluate the cost/benefit impacts of the effects of scale in mandatory versus opt-in programs.

Policy Instruments

As discussed in Chapter 3, where it has been established that under normal market operation the level of demand response required to ensure efficient market operation is not present, policy interventions may be justified. Specific areas of policy measures that may contribute to the growth of demand response markets can be grouped into the following broad categories:

- Retail price regulation – Standard rates and price caps;
- Network regulation – Reliability and security;
- Cost recovery – Subsidies, tax measures and public benefit funds;
- Energy efficiency policy frameworks – Context for demand response;
- Public information programs.

Retail Pricing Policy

It is clear that a consumer can be motivated by price, as has been evidenced by successful retail strategies in liberalised markets. However, the extent to which retail companies have realised the potential of consumer price response remains limited; price regulation may in effect be tying the hands of retail companies. The use of standard rates and price caps, designed to protect consumers from profiteering on the part of retail companies, may also having a corollary effect of limiting the emergence of innovation in retail pricing; that is, pricing frameworks which reflect the fair value of electricity by both time-of-use and by location. Thus regulators should ensure that where retail price regulation remains justified, it is applied with sufficient flexibility so as to allow the growth of more innovative retail products, including demand response.

Network Regulation

The public good attributes of network reliability and security call for clear guidance to market participants regarding the maintenance of minimum acceptable standards. Despite the potential for demand response resources to contribute to reliability and security objectives[103] (often a least-cost solution), this study has shown that the potential has yet to be realised. One potential remedial policy intervention would be to place an obligation on retailers for them to develop a particular amount of demand responsive load. Similar obligations have been placed on retailers for the acquisition of renewable power. However, this approach begs the question of how much demand response would be required and whether contracting for an adequate reserve capacity might be more cost-

103. *Ibid.*, p. 48.

effective. For example, the United States FERC Standard Market Design indicates that both demand and supply resources can be used to meet its proposed Resource Adequacy Requirement, but does not specify the relative proportions.

Despite these challenges, retail demand response obligations should be considered as an option for the least-cost delivery of security and reliability targets.

Cost Recovery Policy

In a perfectly functioning market, with no spillover effects, there would be little or no case for subsidising the market for demand response. Markets should ensure that demand and supply side resources are evaluated and utilised efficiently. In this case, subsidising demand response at the expense of supply resources would lead to economic distortions and lower efficiency.

In practice, more difficult judgements have to be made. It is questionable whether today's liberalised market designs adequately represent the full range of values associated with electricity supply and use in market prices, allowing market participants to judge rationally what are optimal outcomes. Also, in making a comparison between supply-side and demand-side resources, it can be observed that supply-side resources are provided "access resources" (the network and technical interfaces to system operators), generally made available with public funds, while the "access resources" for an enabled demand side (esp. technical interface to the system operators) are assumed to be privately funded.

Absent access to this necessary demand response infrastructure, and recognising the nascent state of the emerging markets (in some cases still characterised by strong retail price regulation, particularly for smaller customers), the use of subsidies has been considered, and is some cases used, within most OECD member country electricity policy frameworks. To the extent that demand response can deliver a more reliable and economically efficient electricity system, there is an argument that some infrastructure investments, such as metering networks, should be shared among all electricity consumers[104]. The lack of hourly metering and data

104. *Ibid., p. 61.*

collection infrastructure effectively creates an insuperable barrier for retailers to offer time-varying pricing services to smaller consumers, particularly given that customers can change suppliers so readily. Rather than consider metering to be a competitive service connected to the retailer, it may make sense to move to a common meter (with an open architecture) that will enable more advanced measurement and control of electricity consumption in the household, independent of the electricity supplier. In a 21st century power system, it would be appropriate to move to metering systems that can enable much greater real-time information for demand response and other end-use energy services.

The principle challenge of targeted subsidies for use in demand response is in ensuring that the response outcomes do not dissipate when the subsidy is removed. Specific and targeted payments, which are limited to individual programs, are more likely to experience this effect. These types of intervention are also often made in the presence of existing market imperfections, rather than dealing directly with issues of market design. The use of subsidy should only be considered when the public good attributes of demand resources have been evaluated and established. A subsidy should not be considered a remedy for flawed market design, and where it is used, it should be recognised as such and complemented by longer term plans for corrective action.

A final note on the issue of subsidies relates to the use of public benefit funds. Some OECD electricity markets have established public benefit funds[105] to provide financial subsidies for use in energy efficiency programs. It is recommended that fund administrators give due consideration to potential energy efficiency contribution of specific demand response program designs[106], when determining the use of such funds.

Tax incentives represent a potential alternative route for policy makers to deliver public policy objectives indirectly into the market place. Support for infrastructure investment in the United States market has

105. A total of 19 American states and the District of Columbia have passed specific public benefits policies to fund energy efficiency programs, with annual budgets totalling more than $800 million.

106. Ibid., p. 56.

been proposed within legislature, in both House and Senate energy bills. Incentives are being proposed to enable more rapid deployment of advanced metering networks and include a new requirement setting a date by which all federal government buildings must be metered, or sub-metered. Under these bills, such devices would have to "enable consumers to respond to energy price and usage signals" and "permit... reading on at least a daily basis". Installation of such devices would then afford the providing utility a $30 dollar tax deduction and a three year depreciation period versus the normal depreciation period of 20 + years. In performing their own financial analysis a major United States utility estimated impacts of these instruments to have a net present value benefit of $196million over a fifteen year study (8 million installed meters, $24.50 per meter)[107].

Information Programs

A common theme throughout this publication is the benefit of increased customer choice. Whilst this may seem to be a common objective of market restructuring, for the most part customers have been left with little else to choose but a lower price.

It could be argued that all participants in the electricity market are aware of the time-value of electricity supply; all except the consumer that is. Unlocking the multiple benefits of increased demand response in the market will require that consumers, too, become aware of this. In the absence of this knowledge consumers will continue to make uninformed choices concerning their individual consumption behaviour. For residential consumers there exists wide scope for improvements in such behaviours: certain household activities, such as laundry and dishwashing, can be done outside periods of peak electricity demand and with minimal inconvenience. Such minor behavioural changes can significantly reduce peak electricity loads and hence prices, without impacting comfort or convenience levels, while returning an economic benefit to the householder.

107. George C. Roberts – Conference Proceedings IEA Workshop on Demand Response in Liberalised Markets February 2003.

Increasing public awareness of these behavioural inefficiencies may be well-served through the use of public information campaigns; however the context of the use of public funded information campaigns is critical. Campaigns, like subsidies, will not resolve problems of market design. A public initiative designed to raise consumer awareness should be considered an essential part of an overall strategy. Such public policy measures should be considered only when the market design and necessary infrastructure is in place to support the message. In such circumstances, public initiatives aimed at increasing knowledge of the value of what consumers are paying for, and how price-setting is impacted by their own behaviours, would increase consumer confidence and their willingness to express their own price preferences.

Finally, there is experience available to guide the development of media campaigns. One study identifies the key factors for making media campaigns effective policy instruments[108] as:

- Targeting the right audience.
- Delivering a credible, understandable message.
- Delivering a message that influences audience beliefs.
- Creating a social context that leads to the desired outcome.

The social context, in this case, includes the policy environment.

108. *Janet Weiss and Mary Tschirhart – Journal of Policy Analysis and Management (1994).*

SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Demand Elasticity

Low price elasticities of demand for electricity are mainly the result of poor incentives and little ability for consumers to control their demand in today's electricity market.
In enabled markets, elasticity is high.

The low price elasticity of demand for electricity in evidence today is a consequence of the limited incentive and capability for consumers to respond to prices in an organised way. Several factors are at work. First, electricity is a non-storable commodity that is consumed as it is produced. This requires demand and supply for electricity in any power system to be balanced in real-time and this balance to be controlled at the wholesale level through a system operator who manages supply resources. Traditionally, system operators have relied upon peak generation capacity rather than demand response to respond quickly to shifts in the demand/supply balance. Second, nearly all customers are able to consume electricity whenever they want and pay the bill later, and therefore they have no direct feedback mechanism to regulate demand. Third, few consumers have been offered price incentives to control their use when they choose to consume electricity. On the contrary, most have been exposed to regulated electricity tariffs that did not reflect the value of the electricity associated with the time of its use. Finally, the technology to monitor or manage electricity demand in real-time (and hence measure and reward changes in consumption behaviour) has been considered too expensive.

However, a situation in which there is low price elasticity of demand leads to high and volatile prices whenever supplies are tight and also makes markets more vulnerable to manipulation. Does this pose an economic problem ? A case can be made that price spikes in electricity markets are symptomatic of the very high value consumers place on a reliable flow of electricity – to be able to consume as much as they are able to whenever they wish to do so – regardless of the cost. However, in today's markets, consumers are not required to value the time-of-use of their electricity demand, so this view is hypothetical.

In fact, not all customers or uses of electricity require the near-continuous reliability that electricity systems have been traditionally designed to provide. Certain industrial customers have long been willing, for a price, to reduce their demand for a limited period (by stopping a single electricity-intensive process, for example) when requested. Residential customers, while valuing overall reliability of their supply, have proven to be willing to curtail certain uses for a limited time (e.g. by turning off residential water heaters) in response to some form of financial incentive. Thus the value of electricity for each customer is not a single number, but rather a range of values depending on the end-use and on the particular customer's preferences. This suggests that the lack of customer incentives and ability to respond to high wholesale electricity prices, rather than inherent consumer preference, is responsible for the relative inelasticity.

The benefits of unlocking this latent demand response are available to, and can be shared by, all market participants. Studies have shown that a 5% reduction in demand would have reduced the highest wholesale prices during California's power crisis by 50%[109].

Significant benefits can be achieved with as little as 5% of demand response capability.

Demand Response Pricing

Since the traditional, vertically-integrated monopoly utility owned all elements of the electricity system, from generator to meter, it was in principle able to capture all the benefits of demand response for reducing costs in generation, transmission and distribution. It therefore was able to

109. Eric Hirst and Brendan Kirby, "Retail Load Participation in Competitive Wholesale Electricity Markets", prepared for the Edison Electric Institute and the Project for Sustainable FERC Energy Policy, January 2001.

offer incentives to consumers to encourage demand response without using electricity prices as an incentive mechanism.

The liberalisation of electricity markets has created competition in the generation and retailing of electricity and separated these functions from transmission and distribution. As a consequence, the incentives to undertake demand response have been dispersed amongst these various parties. However, the true-market cost of producing and delivering electricity should be reflected in the structure of electricity prices, creating appropriate incentives for both demand – and supply-side responses. Such a price environment would enable more efficient price formation, provide the additional resource of demand response to market operation and lead to a more efficient utilisation of assets.

However, there are a wide range of barriers to the transmission of useful price information to customers. The first barrier is the much greater complexity associated with pricing. In liberalised markets, prices fluctuate on an hourly basis or less. Electricity use must be metered to record use over each pricing interval, e.g., if prices are set hourly, the electricity use for each hour of the day must be recorded. Second, those controlling the use of the electricity require some fore-warning of future prices in order to adjust their behaviour accordingly. Ideally, this requires publicly-available price information in advance of real-time that encourages consumers not to consume, and/or greater automation of demand responses based on pre-agreed criteria.

Third, current pricing policies may be a barrier to demand response. For example, a policy that prohibits transmission congestion costs to be passed on, such as "postage-stamp" transmission pricing, will not give a signal for users in a congested region to conserve. Policy makers should ensure that where market designs support locational pricing mechanisms, demand response resources have access to these markets and are eligible to participate. Programs should be designed and marketed in a manner which provides appropriate emphasis to the locational value of such resources.

A further example is in the application of price caps or standard rates. Such instruments serve to dampen the opportunity for the supply-side to communicate constraints and for consumers to participate in the process of natural price formation (common to other bilateral private exchange markets). Consideration should be given to phasing out price caps and the introduction of tariffs based on real costs; tariffs which reflect varying degrees of risk of supply and thus enable real consumer choice.

Enhancing demand response requires giving consumers both the price signals and the means to respond to them.

The use of incentive-based pricing mechanisms is not uncommon for larger industrial consumers, whose large electricity costs justify careful monitoring of electricity prices. Many of these consumers do respond to varying prices during the day – shifting production to off-peak hours or, when prices are high for a prolonged period, shutting down production and reselling electricity they have contracted to consume into the spot market.

However, the situation for small consumers is quite different. The use of price-based incentives is relatively rare and in certain OECD markets load profiling has been used as a substitute for actual consumption monitoring (principally to avoid the expense of an interval meter). Profiling groups consumers en-masse and assumes a single fixed demand curve shape. This in turn has a net averaging effect on changes in consumer consumption behaviour, dissipating the potential to recognise the price response of an individual consumer. This situation is unlikely to change without the increased use of interval metering, where the consumer (or the retailer serving the consumer) is then able to verify changes in demand during particular time and price periods.

Most empirical evidence of the performance of the residential sector to demand response programs has been gathered by regulated utilities. While actual figures vary from program to program, there are a few common conclusions:

■ Customers do respond to pricing incentives to shift load and reduce overall demand.

■ Certain programs which focus on-peak pricing on selected days (critical-peak-pricing programs) appear to have generated stronger demand response.

■ Successful programs require effective communication with consumers, the necessary metering and data collection infrastructure[110] and are those which provide economic gains to consumers without significantly disadvantaging non participants.

■ Inertia is the single greatest factor in determining the level of customer participation – if customers are all enrolled in the program with the option to "opt out" participation rates will be very high. Conversely, programs where customers have to "opt-in", participation rates will be much lower.

Customers will respond to well-designed programs if opportunity, incentives and information are present.

Market Organisation

System operators are increasingly incorporating demand response into their role of balancing energy markets and ensuring the availability of adequate reserves at least cost. The system-led (contingency/emergency) demand response programs currently operated by United States Independent System Operators have evidenced the first signs of the real economic value of demand response capabilities to the wholesale markets. In some cases, benefits have exceeded implementation costs by a factor of five. However, electricity retailers, who have a fundamentally important role to play in developing price-responsive demand in their customer base, are neither active nor, in many cases, financially structured to make the significant investments necessary to involve their customers in demand response.

It has been seen that significant public investment, in the formation of System Operators and for the technologies and business rules for interaction with Supply Markets (generators), is required in the formative stages of deregulation. No similar enabling investments have occurred at the demand-side interface, the result being an apparent lack of demand response. Furthermore, incomplete market designs, characterised by

110. Navigant Consulting 2003.

often complex and intermittent policy intervention, create market uncertainty which is antithetical to a growth in demand response investments.

Retailers and System Operators both have key roles.

Whilst the consumers of electricity ultimately must choose whether or not to participate when faced with pricing incentives, other market participants have important roles to play. The most critical role is played by the energy retailer who must arrange for supply of electricity for their customers under contract. Retailers are at least in principle the best placed to deal directly with consumers and encourage them to adjust their consumption – encouraging them to reduce it when market prices are high and to increase it when market prices are low. Retailers have an incentive to do so even if their contracts with consumers are based on fixed prices (as could be their contracts with power producers), as this would present an opportunity to sell the electricity its customers would otherwise have consumed back to the spot market.

Competition in electricity retail markets will demand increased innovation in new sources of differentiation. As the markets have opened, pure price discounting has been a highly effective pricing strategy to deliver market share growth. In the initial phases of market opening this practice may be effective in capturing and transferring to consumers a part of the early economic efficiency gains brought about by market re-design. In the longer term, and particularly during times of wholesale market volatility and capacity constraint, these strategies may prove not to be sustainable.

That said, few retailers today operating in liberalised electricity markets are offering incentives for their consumers (particularly smaller consumers) to adjust their consumption in response to real price signals. The most successful demand-response programs offered to date have been offered by regulated (and/or state-owned) utilities.

Why is the take-up of these more sophisticated electricity products by retailers so low, given the significant potential for additional profit through price-driven demand response ? There are three possible explanations:

■ Prematurity: In most electricity markets, the opportunity to choose between suppliers is relatively new, and customers are comparing electricity supply offers principally on the basis of flat price discounts.

■ Prices are already low: In the markets where customers have been able to choose suppliers for several years, namely the United Kingdom and Nordpool (until winter 2002-2003), prices have been fairly low and so demand response has not been cost effective for many consumers.

■ However the third and potentially most disturbing explanation is not the degree of customer interest, but the orientation of retailers in the market. Retailing companies tend to have few physical assets, and they concentrate on adding value through trading and brokering. This approach is further encouraged by the ease with which electricity consumers are permitted to change suppliers. This reinforces the reluctance of electricity retailers to invest in physical assets for the consumer. For smaller consumers, who will require an hourly meter to participate meaningfully in time-sensitive electricity prices, the barriers are even higher.

Another critical electricity market participant is the system operator. As operator of a spot market, the system operator has the final role in balancing demand and supply. Early market designs did not recognise an explicit role for the demand side in electricity spot markets or markets for reliability. However, in some cases the incorporation of demand side bidding is now a standard feature of electricity market design and market operators have begun to recognise the importance of the demand side as a resource for both meeting peak demand and for reliability resources. In virtually all cases, more needs to be done by market designers and regulators to unlock the potential of demand response.

Regulation

The main policy question is whether the current failure of demand response to assume its potential market efficiency role (price setting and security of supply) represents a failure of the electricity market, whether policy intervention is required, and what form this intervention might take.

Recognise and measure the demand side contribution.

The relatively low levels of demand-side participation in evidence current in OECD member countries markets' today suggests that disconnected markets, where the demand side fails to respond to tight supply side conditions and excessive market pricing, have already developed. Few business models have emerged within the market to enable repeatable and sustainable demand side participation, a natural market remedy to such failures. Thus it may be concluded that remedial policy intervention is in fact required.

Dealing adequately with the demand-side will require changes to current regulatory models in liberalised electricity markets. Regulatory instruments and policy measures for electricity markets have been introduced to deal with the relatively concentrated and well-known industries of supply and transmission. Retail regulation has focused on matters of consumer protection and ensuring that the ultimate cost to the consumer is a fair reflection of the long-term marginal cost of supply.

An initial and practical step towards unlocking the potential contribution of the demand side will be to establish quantifiable demand response targets. Regulators should be able to test the responsiveness of the demand side, in much the same way as it is able to do so for the supply side. In so doing regulators will be better placed to ensure system reliability and public good objectives.

The following specific reporting measures for demand response should be considered:

- Percentage of customers on variable price products by segment (for use in market-led response);
- Percentage of responsive base load and peak load by segment (for use in system-led response);
- Actual demand response delivered (segment elasticity measure);
- Location of demand response resources (network regulation impacts);
- Environmental impacts of delivered demand response.

Initial reporting will enable regulators to establish benchmarks for performance and to quantify the economic, efficiency and environmental benefits. This first phase of evaluation will be a critical step in ensuring policies which impact pricing, market design and investment are developed, targeted and applied effectively.

In addition regulators should re-visit market power test procedures and ensure that the potential benefits of demand response to limit market power abuses are duly recognised.

Market Power Test – Doubling the price elasticity of demand has the same impact on market power as halving concentration on the supply-side.

Finally, based on the evidence provided within this study, governments should decide whether, in principle, demand response is a necessary component of market design to ensure long term efficient and reliable market operation. If increasing demand response thus becomes a clear objective of liberalised markets, regulators should develop and communicate strategies to remove unwarranted uncertainty from demand response markets (some OECD markets such as the United States (FERC), NZ and certain Australian States have already begun this process). Such strategies should address, as a minimum:

- Short and long-term plans for pricing regulation (where applied);
- Public good aspects of increased demand response and associated cost recovery mechanisms;
- Investment requirements for demand side infrastructure (metering and communications);
- Technical standards of performance of demand response resources;
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