9 Peak demand and demand management

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| Key points |
| * Heat waves, cold snaps and other often short‑lived and infrequent events can create major spikes in electricity usage, known as ‘peak’ or ‘critical peak’ demand. The magnitude of peak demand has risen over the last decade, driven primarily by growth in residential air conditioning. Other factors, including normal industrial usage, can add to demand during peak periods. * Peak demand is a key driver of investment in generation and network capacity, the costs of which are ultimately borne by all electricity users. For example, in New South Wales, capacity that caters for less than 40 hours a year of electricity consumption (or less than 1 per cent of time) accounts for around 25 per cent of retail electricity bills. * ‘Demand management’ involves using price and non-price measures to curtail customers’ use of electricity during peak demand periods, including shifting electricity usage to non-peak times. * Most large industrial and commercial users are subject to demand management, but network charges generally fall short of being cost-reflective, with only a small share of businesses facing much higher network charges at peak times. * Currently, demand management amounts to less than 2 per cent of NEM-wide peak demand. * Most households are not provided with such incentives. Rather, under current ‘average’ network pricing, the substantial additional costs of meeting peak demand are spread across all households and time periods. This smoothing of prices: * encourages high consumption at peak times and inefficient supply-side investment * results in electricity bills being higher than necessary over the longer term * may create inequities, with low income consumers cross-subsiding the better off. * By signalling the much higher costs of drawing on system capacity at peak times, demand management approaches can give consumers strong incentives to economise, where feasible, on electricity usage during peak demand periods — and would reduce the cross-subsidisation of ‘peaky’ consumers. * The adoption of demand management by electricity network businesses appears low. Chief among the possible causes are a poor understanding of potential benefits by consumers, smart meters not being widely available for residential users and distribution businesses facing conflicting incentives to pursue demand management. * The rollout of smart meters and the adoption of critical peak pricing would reduce the required level of capacity of the network and, more broadly, lower the operating costs of managing the network. In regions with impending capacity constraints, the savings per household could be around $100–$200 per annum, but a rapid mandated NEM-wide rollout could readily produce net costs for Australians. |
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## 9.1 What is peak demand and why is it a problem?

Demand for electricity is inherently variable and can fluctuate from hour-to-hour, day-to-day, season-to-season and year-to-year. The causes are numerous, and include both random and habitual consumption behaviours, business and sleeping hours, and seasonal and daily changes in outdoor temperatures. As well as the common fluctuations in electricity usage seen through each day and across the year, sometimes there can be major spikes in usage, for example during unusually hot days (figure 9.1).

Figure 9.1 The impact of temperatures on the profile of daily load

Queensland MVA

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*Data source*: Topp and Kulys (2012).

In contrast to the variable nature of electricity demand, network capacity (which is determined by the technical design limits of individual network elements) cannot be increased in the short run. As network usage approaches or exceeds capacity limits, there may be damage to equipment and loss of network performance, which could even lead to a partial or full system shutdown (AEMC 2008b).

As it is currently not economic to store electricity at its point of use, avoiding supply failures requires networks to be built to reliably exceed peak demand. That is, they must be able to accommodate the highest draw of power from end users in any instant.

This means that infrequent and short periods of high electricity consumption can require a disproportionate share of generation and network investment, which in turn drive up the cost of electricity generally. This is the problem of ‘peak’ demand (or ‘critical peak’ demand, as the problem of major spikes is sometimes called).

Commentators have used different metrics to demonstrate the scale of the problem in the National Electricity Market (NEM). For example:

* around 20−30 per cent of the $60 billion of electricity network capacity in the NEM is used for less than 90 hours a year (AER 2012q, p. 15)
* capital expenditure to accommodate ‘peak load growth’ accounts for around 45 per cent of approved total expenditures in the distribution network, and slightly more than 50 per cent in the transmission network (AEMC 2012f)
* around 25 per cent of retail electricity bills in New South Wales reflect the cost of system capacity that is used for less than 40 hours a year (or under 1 per cent of time) (DRET 2011, p. xxii).

Although peak demand dipped slightly during the 2010‑11 and 2011‑12 (mild) summers, it has been trending up over the last decade.[[1]](#footnote-1) To cater for this growth, there has been significant generation and network investment. Over this period, though, total demand has been flat or falling in the NEM. This has caused the utilisation of network assets to decline, contributing to a fall in multifactor productivity (figure 9.2).

Figure 9.2 Electricity supply: inputs, output and multifactor productivity

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*Data source*: Topp and Kulys (2012).

It is not surprising that people demand significantly more power when outside temperatures are particularly hot or cold. Consumers may well place a very high value on the comfort and amenity gained from their use of network capacity during periods of peak demand.

Growth in peak demand therefore need not indicate an economic problem, at least not on its own. Rather, the issue is whether the level of peak demand is economically efficient. This depends on whether the amenity and other benefits that consumers gain from their peak electricity consumption are at least commensurate in value with the high cost of having it supplied.

Appropriately structured time-based prices that reflect those high costs would help to confirm this. Faced with such price signals, consumers would have a financial incentive to consider reducing or shifting the timing of some or all of their peak electricity use, and suppliers would receive a signal about the value that consumers place on additional peak capacity.

However, as discussed below, little use is currently made of cost‑reflective, time‑based network pricing. Some businesses face prices that partially reflect supply costs, but this is confined mainly to wholesale energy costs[[2]](#footnote-2) rather than reflecting the costs of peak network capacity. Most households and many small businesses face average (or flat) network tariffs, which means that the substantial additional costs of meeting peak demand are spread across all households and time periods. These consumers thus have little incentive to economise on their usage in peak periods, so peak consumption exceeds what would likely be observed were consumers to face prices reflecting its true cost.

The upshot is that, in these circumstances, growth in peak electricity demand is likely to be inducing (or bringing forward) a sizable stream of potentially unnecessary investment, for which consumers ultimately pay. And the widening gap between peak and average demand is contributing to reduced productivity in the electricity sector.

## 9.2 A roadmap for how this report addresses peak demand management

### This chapter

This chapter is the first of four relevant to the problem of peak demand as a driver of electricity network costs, and appropriate solutions to it. It highlights that, if left unfettered, peak demand and electricity costs would continue to rise inefficiently. It then establishes a rationale for demand management to reduce spending on peak‑specific network capacity and limit future increases in electricity bills.

Accordingly, having already outlined why peak demand is a problem (section 9.1), this chapter:

* examines in more detail the various facets and causes of the problem (section 9.3)
* explains how the tools of demand management, including both cost-reflective pricing and non-price measures, can potentially address peak demand (section 9.4)
* investigates the extent to which demand management is applied across the NEM (section 9.5)
* outlines reasons for the limited uptake of demand management to date (section 9.6)
* examines estimates of the prospective benefits and costs from the further adoption of demand management in Australia (section 9.7).

### The following chapters

Chapters 10, 11 and 12 address barriers to demand management, with the associated recommendations forming a package of interrelated reforms:

* chapter 10 assesses the technologies required to implement demand management, including the need for smart meters to allow time-based pricing and achieve other forms of demand management
* chapter 11 evaluates the role of cost-reflective (time-based) network charges that allow consumers to reveal how much or how little investment in distribution capacity they value. It outlines the importance of a carefully managed transition, along with measures to address equity and affordability concerns and to support distribution business’s engagement with retailers and community consultation
* chapter 12 examines reforms that would be complementary to the transition to time-based pricing including:
* the rules that govern how networks convert the allowed revenues from network determinations into customer charges, and in particular, whether networks should operate under a revenue cap or a weighted average price cap
* the incentives faced by network businesses to pursue demand management compared with investment in traditional network assets, and the role of the Demand Management and Embedded Generation Connection Incentive Scheme in encouraging demand management options
* the important role retail price regulation currently plays in determining the prices faced by consumers, and the feasible transition to removal of such regulation.

### Scope of the analysis

The terms of reference for this inquiry focus on network expenditure. Accordingly, the Commission’s treatment of demand management gives prominence to achieving network efficiencies. Nevertheless, managing peak demand for network services can also lower generation costs. The Commission has taken account of the potential for such benefits in its empirical analysis (section 9.7).

The terms of reference for this inquiry also direct the Commission to have particular regard for the Australian Energy Market Commission’s (AEMC) Power of Choice review. The broad scope of that review goes beyond the Productivity Commission’s consideration of demand management, which focuses on the potential to limit network expenditure and associated prices. The Commission has also taken into account the intermediary role of retailers. Effective demand management requires that cost‑reflective network charges passed on to retailers are also passed on to consumers.

The Commission has given less attention to several initiatives seen as priorities by the AEMC in itsfinalPower of Choice report (released in November 2012). For example, the AEMC has suggested changes targeting areas where there is evidence of ‘low hanging fruit’, including harnessing the demand management potential of industrial and large businesses users. The Commission agrees that early action in these areas would be beneficial, including the application of more efficient network charges to commercial end-users. Instead, the Commission has focused on changes that are of a longer-term nature, focused on the contribution that households make to peak demand — gradually taking effect over the medium to long term.

## 9.3 Facets of the peak demand problem

There are several different facets to the peak demand problem. Understanding them and their causes is critical for devising efficient policy solutions.

### There are multiple types of peaks

#### Localised network peaks

Peak demand that strains network capacity can occur in localised areas within the distribution network. It typically occurs in the late afternoon and evening on hot summer days or in the early morning on very cold days. These peaks in demand, and the network congestion that can result, come about because of demand and supply characteristics, including:

* the coincidence of similar end uses, such as the time most people arrive home from work and turn on their air conditioners, or in areas of the network with similar industrial uses
* the limited levels of spare capacity in some areas of the network experiencing increasing congestion and approaching an investment ‘trigger point’ (and, to a lesser extent, the configuration of the network[[3]](#footnote-3)).

Such peaks most commonly present at the zone substation level of the distribution network, because users with similar demand profiles tend to congregate in a geographical area, often due to local planning restrictions. (A high concentration of similarly ‘peaky’ users in a local network area will result in a network load profile that is far peakier than one that includes a mix of residential, business, commercial and industrial users.) Further, according to Oakley Greenwood:

Because different parts of the network serve different sets of customers, peak demand from the network perspective is essentially a local matter and is based on the area and specific set of customers served by that part of the network. (2012a, p. 23)

#### Whole of system peaks

As well as localised peaks, ‘whole of system’ energy peaks can occur if demand reaches very high levels across the NEM, or within a NEM region. In such instances, energy prices in the wholesale spot market can spike and large transmission lines (including interconnectors) may reach capacity. Some generation capacity only exists to deliver electricity during wholesale market spikes.

Retailers must also manage the risk of high wholesale pool prices during whole-of-system peaks, which they do through a variety of tools including purchasing various financial derivatives, purchasing supply contracts from generators, or owning generation assets themselves. Each of these approaches is supported by the existence of a ‘natural hedge’ — that is, where price fluctuations result in profits to generators that are perfectly offset by losses to retailers and vice-versa (appendix C). Managing the risks of whole of system peaks, therefore, adds to the cost of retailers supplying energy to their customers.

Many factors can of course contribute to wholesale price spikes. These include intra‑regional transmission failures, interconnection capacity constraints, generation failures or disorderly bidding. However, as the Australian Financial Markets Association (AFMA) indicated, days with high demand are generally a pre-requisite:

The few days with high maximum prices are associated with periods of high demand with only a very small number of exceptions in the 870 day sample [from January 2009 to May 2011]. Conversely, periods of low demand are unlikely to be associated with prices in excess of $300/MWh. (AFMA 2011a, p. 3)

In most states in the NEM, demand peaks occur most frequently during summer (figure 9.3). The peaks are caused by the combined electricity use of industry, retail and residential consumers, but tend to occur when large numbers of people experience very hot conditions on normal workdays (Ernst & Young 2011).

Figure 9.3 Seasonal timing of peak demand

Highest 100 half hour periods of energy use in each state between 1999–2011a

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a Where the data do not add to 100, it is because the peak demand period sometimes occurs in spring.

*Data source*: Ernst & Young (2011).

#### Addressing whole-of-system versus local peaks

Wholesale price peaks will often coincide with local network peaks, but the two can occur independently or may overlap only to a limited extent:

Network peaks most commonly occur in the distribution network, and will not necessarily coincide with peaks in the wholesale spot price for electricity. (NESI 2011, p. 74)

Notwithstanding such unpredictability, it is typical that:

* peaks in wholesale energy demand occur late in the afternoon around 4 pm and include a large proportion of business and major industrial loads
* local network peaks will occur in the early evening, usually between 6‑8 pm, and are associated with a higher proportion of residential load.

A demand management solution to address a localised network peak will typically be designed differently from one addressing a whole-of-system peak that causes wholesale prices to spike (though a single technology platform can be used to implement solutions addressing both peaks[[4]](#footnote-4)). Even still, there may be interactions between demand management approaches designed to affect network or wholesale market peaks. As recognised by the Australian Energy Regulator (AER):

… an initiative targeting reductions in network peak demand could also provide additional benefits to the wholesale market (in terms of the deferral of generation capacity). (AER 2012c, p. 2)

Adapting demand management to the relevant geographic area is particularly important for managing local network peaks. A threshold reduction in peak demand is required to defer a capital project and the annual deferral value — that might instead be spent on a demand management solution — varies considerably depending on inherent supply costs.[[5]](#footnote-5) As the AEMC notes:

Regional variations in demand quantum and timing, and the regional basis of infrastructure planning decisions, mean that efforts to influence peak demand from a top down, whole of market level may need to be tailored to the local market characteristics. (2012g, p. 1)

In contrast, managing whole of system peaks is less contingent on a specific quantum of demand, with all load reduction being of some value.[[6]](#footnote-6)

### Peak demand is growing and becoming more ‘peaky’

While determinants of peak and average demand overlap (box 9.1), since 2007‑08 average demand has been flat or falling in the NEM but peak loads have been trending upwards over the longer term (figure 9.4). Thus, the gap between peak and average demand is widening (albeit with some exceptions, generally observed during a run of milder seasons).

Figure 9.4 Rising peak demand and its increasing ‘peakiness’

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*Data sources*: ESAA *Electricity Gas Australia*, various issues.

Year-to-year variation and short-term shifts in prevailing weather conditions create ‘noise’ around longer-term trends in peak demand growth. This can complicate the forecasting of peak demand and planning of network augmentation to accommodate expectations of growth. Seasonally adjusted estimates attempt to correct for weather driven variation in peak demand in NEM regions.

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| Box 9.1 Determinants and forecasts of demand |
| The growth of peak electricity demand reflects prices and a variety of economic, policy and structural determinants. Apart from electricity pricing levels and structures, relevant factors underlying growth rates include:   * economic prosperity and both the penetration of household air conditioning to address seasonal temperature variability, and the size and design of houses (especially the trend to two story houses with no eaves) * the penetration of rooftop photovoltaic systems, which can reduce the average demand for electricity drawn from the network that is supplied by traditional large scale generators, but have less impact on reducing peak demand * broader economic conditions, both domestically and internationally, and population growth driving new connections * the outlook for large industrial uses and specific sectors, such as mining and manufacturing * policy settings, including energy efficiency initiatives, and changing consumer preferences.   Although peak and average demand have many of the above determinants in common, their rates of growth will not always move in tandem or at the same rate.  Growth in peak demand is forecast to be lower than in previous years, but is projected to continue to grow in the longer term (AEMO 2012a). Over the next 10 years, annual growth in peak demand across NEM regions is forecast to range between 1‑2.5 per cent. This forecast is a revision on previous estimates, such as in the annual *Electricity Statement of Opportunities* (AEMO 2011b), which predicted annual growth rates in excess of 4 per cent in some regions over the next 10 years. These estimates, though, are sensitive to the incidence of extreme daily temperatures.  Annual energy (or average) consumption is projected to be 2.4 per cent lower in 2011‑12 than 2010‑11, and over the next 10-year period, average annual growth is forecast to be 1.7 per cent (AEMO 2012a). Power prices and economic conditions principally underpin average demand growth, although other determinants of industry performance such as the level of the Australian dollar will also affect the derived demand for electricity. |
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While long-term forecasts of peak demand generally assume continued long-term growth, most regions of the NEM experienced relatively mild summers in 2010‑11 and 2011‑12, which resulted in a lower rate of peak demand growth compared with earlier years (box 9.2). In the absence of policy changes (or structural shifts from technology and appliance changes) affecting the underlying determinants of peak demand, a greater number of future peak events is expected (on average) than has occurred over the last two years.

Because investment in additional capacity is generally forward-looking and ‘lumpy’ (driven by economies of scope and scale, with an expectation of continued growth in demand) the utilisation of network assets typically falls following such investment. In addition, the fall in network utilisation following investment has been compounded by the much flatter (or even falling) growth in average consumption across the NEM. Accordingly, the utilisation of network assets has declined in most states (chapter 6), which has contributed to the decline in measured multifactor productivity (figure 9.5).

Figure 9.5 Peak demand growth reduces productivity

Multifactor productivity index

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*Data source*: Topp and Kulys (2012).

The ratio of average to peak demand (also referred to as the ‘load factor’ or the peakiness of demand) significantly affects the cost of supplying electricity. As an indication of the long-term gains from reducing peak demand (and narrowing the gap between average and peak demand), a move from a 38 per cent to a 50 per cent load factor would reduce an average electricity bill in 2015 by about $245. This is equivalent to about $1.6 billion per annum across the NEM (Simshauser 2012).

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| Box 9.2 The cyclical impact of climate muddies the long‑term trend |
| Peak electricity demand in Australia is most common on very hot days. In 2010‑11 and 2011‑12, there was a decline in the frequency of very hot days. However, 2013 has produced the hottest January on record. A recent publication by climate scientists provides a longer-term context to these recent weather events. In the most recent *State of the Climate* report, the CSIRO and the Bureau of Meteorology said:  Australian annual-average daily mean temperatures showed little change from 1910 to 1950 but have progressively warmed since, increasing by 0.9°C from 1910 to 2011 …  The warming trend has occurred against a backdrop of natural, year-to-year climate variability. Most notably, El Nino and La Niña events during the past century have continued to produce the hot droughts and cooler wet periods for which Australia is well known. 2010 and 2011, for example, were the coolest years recorded since 2001 due to two consecutive La Niña events. (2012, p. 3)  In the eight years prior to those La Niña events, the average number of days where the maximum temperature exceeded 40° Celsius (averaged across reporting weather stations throughout Australia) exceeded 14, compared with less than 11 days in 2010 and less than seven days in 2011.  Australia’s seasonal climate is inherently variable  Average number of days over 40°C   |  | | --- | |  |   The decline in the number of very hot days in 2010 and 2011 is not evidence of an end to the long‑run warming trend (BoM 2012). Instead, it follows similar patterns to most other La Niña events (such as those in 1999 and 2000), when there was a reduction in the frequency of very hot days, highlighting the substantial impact that climate variation has on weather events in different years. As such, in future, the frequency of very hot days is projected to increase. |
| *Sources*: BoM (2012); CSIRO and BoM (2012). |
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### Household usage is a major contributor to peak demand

Household consumption accounts for less than one-third of total electricity use but has important implications for peak demand, with some estimates showing it may account for more than two-thirds of peak loads (NERA 2008a). Of course, the contribution to peak load at a given network asset may be much higher or lower than this, depending on the proportion of household users within localised areas of the network (compared with commercial and industrial users). For example:

* the Commission has been told that, for some zone substations, 80 per cent or more of the customers will be residential
* even if the share of residential load to other uses is 50:50 at other substations, during peak times, residential load will generally make up a higher proportion of the load.

When residential demand peaks, the load on the network will typically be about double that experienced on an average day around the same time (figure 9.6).

Figure 9.6 Household peak loads are very peaky

Household electricity demand (kW), by time of daya

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a Based on interval meter data from 3000 Sydney households in the financial year 2010. The maximum day load is the load profile for the day of maximum peak demand for the financial year, while the average daily load is the average for all days in that year.

*Data source*: Simshauser (2012).

Factors that affect household electricity use during peak periods may include consumers’ income,[[7]](#footnote-7) the types of electrical appliances they own and the pattern of use, lifestyle factors and weather events. These factors also change over time, such as from the increasing penetration of solar panels and a range of government-initiated energy efficiency programs (although each of these factors has primarily affected average demand, with a lesser effect on peak consumption).

In response to recent increases in network and energy prices, total household (and business) consumption has displayed a ‘conservation effect’ — that is, average consumption has decreased as consumers seek to limit their bills (AEMO 2012a, p. v). Households are willing to reduce their power usage under the right circumstances. An ABS survey (though rather dated), found that 88 per cent of households had taken steps to limit their power use and conserve energy due to price rises and other, largely environmental, reasons (ABS 2010). Higher prices will also encourage some reduction in consumption during peak demand periods. However, if higher prices came in the form of a flat network charge, consumers would likely reduce their demand across all periods, with only a modest reduction in peak demand.

Demand management tools targeting peak consumption are much more likely to be effective. The tools include critical peak pricing (higher prices during periods of peak demand) and direct load control (where consumers agree to have some of their electricity use curtailed at peak times).

Currently though, even where metering allows higher peak-time charges for residential users, the network component of these charges only vaguely reflect underlying costs (including simple and predictable shoulder, off-peak and peak charges).[[8]](#footnote-8) As such, peak demand (typically confined to the handful of days each year) has been minimally affected.

### Residential air conditioning is the main contributor

According to the AEMC:

The increasing penetration of air conditioning, particularly in the residential sector, has been cited by network businesses as a key reason for increasing maximum demand. (2011a, p. 10)

The extent of this growth is shown in figure 9.7.

Figure 9.7 The increase in household air conditioning

Per cent of households with air conditioning

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*Data sources*: ABS (2011d), Topp and Kulys (2012).

The national stock of air conditioners doubled in the 10 years to 2008, and by 2020, the associated use of electricity is projected to be five times greater than it was in 1990 (DEWHA 2008, p. x). Rising incomes, hotter weather and the declining cost of air conditioners are key causes of this trend. Other factors include new homes that are much larger than in the past[[9]](#footnote-9) and the increasing use of multiple air conditioners and multi-systems (particularly by higher income households).

The age of air conditioners and the way they are used can also significantly affect their contribution to peak demand and, in turn, network costs.[[10]](#footnote-10) In most climates, air conditioning is used for a low proportion of the time — typically for the hottest parts of hot days. As such, they draw significant amounts of energy during peak demand periods, but little or no energy for most of the year, resulting in a very low load factor (ratio of average to maximum consumption). For example, residential air conditioning accounts for 20 per cent of annual electricity consumption, but can account for the majority of the increased residential load during a peak demand event.

Most other household appliances (such as refrigeration) have a much flatter load profile, with a load factor of around 60–70 per cent — hence, contributing less to the peak demand problem. Similarly, industrial and commercial uses of electricity also have much flatter load profiles (LaCommare et al. 2002).

Some 56 per cent of households cite that their main reason for using an air conditioner is (or would be) to sleep better (Galaxy Research 2012). On the basis that overnight use would be unlikely to contribute to peak demand, it would not be as costly to service such demand and, if network prices reflected that cost, consumers could even increase their comfort level more than they might otherwise have chosen. This highlights that it is the use of the appliance (including the timing of use and resulting load factor), rather than the appliance itself, that is the key determinant of its contribution to peak demand.

Given its impact on network investment and the potential to encourage behavioural change in its use, air conditioning:

… attracts considerable political and policy attention due to its very poor load factor and the potential to create major problems for the electricity generation, transmission and distribution systems on peak summer days. (DEWHA 2008, p. x)

As an indication of the costs of expanding the network to accommodate peak loads from air conditioning, it has been estimated that a 2 kilowatt (electrical input) reverse cycle air conditioner could impose a system‑wide cost of up to $7000 (DRET 2011).[[11]](#footnote-11) While this estimate illustrates the high costs of investing in incremental units of network and generation capacity, in the Commission’s view, it is likely to overstate the actual cost of air conditioning, since:

* it fails to take account of the different asset lives of air conditioners and the infrastructure in the electricity system that provides capacity
* it assumes that the appliance is always operating during peak demand periods — about 30–35 per cent are normally turned off (CRA 2006; Swift 2005)
* it assumes that all air conditioners are running at full capacity when operating during peak consumption — a more realistic figure may be 80–90 per cent.

Nevertheless, even after allowing for these factors, a crude estimate of the system‑wide cost of a reverse cycle air conditioner that is used mostly during peak times is probably still around $2500. This estimate represents an implicit subsidy of $350 per year to customers who own and use air conditioners at peak times, paid for through higher bills for all other customers.[[12]](#footnote-12)

#### Reasons and scope for change

Flat network tariffs effectively hide the costs of supplying additional peak capacity to meet the increased use of air conditioning, and therefore provide consumers no financial incentive to change their consumption behaviour. The upshot is that people who own air conditioners (and use the appliance intensively at peak times) are subsidised by those that do not.

As well as this giving rise to inefficiency, it affects distributional outcomes, since lower income households tend not to own (or own fewer) air conditioners. ABS surveys indicate that higher income households generally have a higher rate of air conditioning (one or more air conditioners), compared with lower income households. Further, there is some evidence to show that expectations of thermal comfort increase with income and the thermal efficiency of dwellings (the likelihood of which increases with income) (ABS 2009, 2010).

More recently, the growth in the number of households with air conditioning has started to slow and may be reaching saturation in some areas. Nevertheless, the number of months of the year air conditioning is used is increasing over time — one‑third of households used their air conditioner for 3–6 months of the year in 2008, up from a quarter of households in 2002. Further, there is no sign that the increasing use of multiple air conditioners and multi-split systems will cease in the near term.

While growth in peak demand from the increased penetration of household air conditioning is a dilemma for network businesses, it does not automatically mean that targeting their use will provide the most effective solution. When demand is at its maximum, any source of demand reduction can potentially relieve network congestion. As stated by Charles River Associates, in evaluating feasible demand management options:

… [demand management] does not need to come from an end use that is causing peak demand to grow. Rather, any end-use load that can be reliably reduced when the network area experiences a peak is useful … (CRA 2004, p. 14)

However, demand management trials generally show residential customers with air conditioners activated on very hot days are most flexible about reducing their peak consumption (Futura 2011). Further, in many localised network areas, there would be limited scope to substitute reductions in peak demand use between residential and business users, especially in network areas where household peaks in demand occur much earlier or later than usual business hours (figure 9.6). This means it is important that any solutions consider incentives for households to economise on peak power use. Ideally, to yield network savings, any incentives should target both the specific times network congestion is experienced and households whose load reduction would help to relieve such congestion.

## 9.4 What is demand management and how can it provide a solution?

Demand management[[13]](#footnote-13) offers a potential solution to the problem of peak demand by providing incentives for consumers and businesses to reduce consumption at peak times and, where possible, shift the timing of their power use to non-peak times.

### Potential benefits of demand management

The economic potential for demand management arises because it can:

* avoid an inefficiently high rate of peak demand growth, delaying the need for network augmentation and reducing the size of peak-specific network investments
* improve the utilisation (and productivity) of supply side capacity by shifting the timing of electricity use and reducing the gap between average and peak consumption — achieving allocative efficiency
* decrease investment in costly peak-generation and reduce generation costs by reducing reliance on higher cost peaking supply (such as open cycle gas turbines)
* improve competition and reduce the ability of an individual generator to exercise market power in the wholesale market during congestion at peak periods (Borenstein 2005; Borenstein and Holland 2005; Bushnell 2005; Joskow and Wolfram 2012)
* improve supply reliability, including increasing load shedding options and assisting with the restoration of power after loss
* reduce volatility in demand (and wholesale prices)
* allow operational efficiencies for network businesses, including from advanced metering infrastructure, which enables remote access to consumption data, assists with more timely and less costly disconnection and reconnection, and improves network planning and detection of outages
* in the short term, provide scope for some consumers to receive reduced electricity bills and, in the longer term, could slow the rate of growth of future electricity bills for all consumers.

The focus of this report is on the potential for demand management to delay the large capital cost of expanding supply-side capacity and to improve the overall efficiency of network infrastructure. An investment that is too early or too large will not be productive, especially if it is used very rarely *and* consumers would not gain sufficient benefit to justify the cost of the additional capacity.[[14]](#footnote-14) Importantly, as noted earlier, reducing peak demand and associated supply side investments is not itself an objective, with reductions in peak consumption only desirable to the extent that the costs of peak consumption exceed end users’ valuation of it. However, allowing consumers to reveal their preferences can avoid an *inefficient* rate of peak demand growth and, in turn, improve network utilisation.[[15]](#footnote-15)

### Demand management options

Options to implement demand management are broad and can include a combination of more cost-reflective pricing, negotiated load management programs and distributed generation solutions (chapter 13) (table 9.1). Such measures can also combine with information-led behavioural change. Some measures will be more effective at targeting peak consumption than others, and each will involve different costs to implement. For example, many energy efficiency measures have a ‘conservation effect’ by reducing consumption across all periods, rather than just ‘clipping the peak’ or shifting load.[[16]](#footnote-16)

Table 9.1 Summary of demand management approaches

|  |  |  |
| --- | --- | --- |
| Name | How it works | Technologies involved |
| Cost-reflective pricing | Charging customers different amounts for their consumption at different times of the day or year, reflecting the varying costs of delivering electricity at different times of year. These price signals could shift consumption away from the peak. | Advanced/smart meters and associated infrastructure and billing systems.  Information and control tools assist consumers to respond. For example, in-home displays and whole house gateway systems allow appliances to be individually controlled and automatically adjusted in response to prices. Web portals, SMS and email technologies notify customers in advance of high prices and load control events. |
| Residential direct load control programs | Networks, retailers (with the agreement of customers) or customers, automating the response of household appliances such as air conditioners during network or wholesale ‘peak’ events. | ‘Demand response enabling devices’ (DREDs) and communications infrastructure to interact with them. The ‘enabling device’ can include a smart meter. |
| Industrial and commercial load management contracts | During ‘peak events’ and subject to pre-agreed terms, industrial or commercial equipment is turned down or off by a network or retailer, or an aggregator working on their behalf. Usually the user can opt out at some cost (based on pre-agreed terms). | A variety of options, from manual responses via emails and SMS, to automated responses with the use of ‘Building Management Systems’, ‘Supervisory Control And Data Acquisition’ systems, ‘Site Servers’ and ‘Network Operation Centres’. |
| Distributed generation  (chapter 13) | Produces electricity close to its point of consumption, such that it does not need to pass through all or any of the network. A variant on this is ‘fuel substitution’, in which customers are switched from electric to gas appliances. | Gas co-generation, gas tri-generation, standby generators, gas heating and solar PV. |
| Energy efficiency | Lowers the electricity demands of appliances, including during peak events. | Wide ranging. Many approaches do not have a targeted impact during peak events. |

*Source*: EnerNOC (pers. comm.).

### Consumers respond to price signals

A potentially key tool of demand management is the use of electricity prices that vary to reflect the costs of supply at different times. In principle, such approaches should help ensure that peak network capacity is available for high value uses, in part by allowing cheaper non-peak prices for lower value or less time sensitive uses. Of course, price signals already play a key role in people’s decisions about what, when and how much to consume of many different goods and services, and they are also used to ration scarce capacity in some network industries. Thus, differences in airfares will often influence not just which airline, but also which flights travellers choose; while in previous times, cheaper rates after 9 PM. encouraged many people to delay their (then expensive) long‑distance telephone calls. Although not used extensively to date in Australia to manage the electricity demand of households, price signalling appears to the Commission to offer significant scope to do so.

However, since the implementation of time-based network pricing in the electricity market would not be costless and would be a significant change for most consumers, it is sensible to assess the empirical evidence about the performance of pricing approaches in electricity, and in particular to what extent consumers respond to price signals.

Most studies find that Australian consumers do adjust their consumption in response to time-based pricing. For example, across seven Australian pricing trials, the average reductions in peak demand were between 13–40 per cent (Futura 2011). The extent of response by consumers of course depends on the strength of the price signal and consumers’ ability to adapt. In particular, when prices are considerably higher during a declared peak event — so-called critical peak pricing — the reduction in peak consumption is generally more than four times that under flatter ‘time of use’ tariffs (ESAA, sub. 23, p. 29; Faruqui and Palmer 2012; Futura 2011). (Further empirical evidence on consumer’s price responsiveness, and flexibility with the timing of their electricity use, is summarised in box 9.3.)

Pricing on its own may not be enough to support an efficient consumption response — a point made by the Standing Council on Energy and Resources:

Many consumers have limited knowledge of and engagement with their electricity consumption and may not understand the new pricing structures sufficiently well to take advantage of new opportunities. (SCER 2011a, p. 16)

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| --- |
| Box 9.3 Consumption responsiveness to time-based prices[[17]](#footnote-17) |
| Findings of studies examining households’ responses to time-based electricity pricing include:   * consumers primarily shift power from peak to non-peak times, but total demand also falls (the ‘conservation effect’), although usually by no more than 10 per cent (Simshauser 2012) * the more extreme the climate in a particular region (either hot or cold), the greater the responsiveness * households with air conditioners are consistently more responsive at peak times than those without. Moreover, houses with air conditioning usually demonstrate a capacity to shift their load into non-peak periods, rather than only reduce their total consumption (CRA 2005; Futura 2009; NERA 2008b) * households are generally less responsive to high peak charges during winter, which is relevant to some regions in New South Wales and Tasmania, where winter peaks are higher than summer peaks * although consumers will normally continue to show some responsiveness to successive price increases during peak events, the incremental response tends to tail off (Borenstein and Binz 2011; Caves et al. 1984; Faruqui and Palmer 2012; Faruqui and Sergici 2010; Simshauser 2012). Such a result is consistent with increasingly fewer discretionary uses being available as consumers curtail their load in response to higher and higher prices. As an extreme example, the Ausgrid Strategic Pricing Study found no greater response among customers facing a peak to off-peak price ratio of 31 than among those facing a ratio of 13:[[18]](#footnote-18) * However, some customers facing the higher price did not have in‑home displays, unlike all consumers facing the lower price (Futura 2011). * the addition of technology to automatically turn off, turn down or cycle appliances, or notify homeowners of critical peaks and other price information, increases the average response (Faruqui and Palmer 2012). For example: * notifying customers (usually 24 hours) in advance of a critical peak event (such as through email, SMS, web portal, or using an in-home display) assists consumers to prepare to shift their load, maintain their comfort and reduce the possibility of inconvenience * in the absence of price signals, assistive technologies and information about energy use generally has little impact (Ausgrid strategic pricing study and California state‑wide pricing project). |
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Nevertheless, as discussed in box 9.4, imperfect information, along with cognitive and behavioural traits among consumers, do not preclude the use of pricing to manage demand, although they may have implications for how such pricing is introduced and the role of complementary reforms.

For example, with the agreement of customers, tools to assist consumers to reduce their consumption during peak hours and to take advantage of lower prices at all other times may complement demand management. Tools could include:

* technologies and devices to communicate consumption and pricing information to consumers, which allow them to modify their behaviour to achieve energy savings
* access to demand management services and programs (such as those provided by retailers or other third parties). For example, a customer may choose to participate in direct load control of appliances to ensure that lapses in their monitoring of prices or appliance usage would not expose them to high bills
* access to education on options to change consumption habits.

Acceptance of new pricing arrangements can be encouraged by educating consumers about the real costs of peak-time consumption. People may be willing to change their behaviour if they are aware of the broader benefits of curtailing peak demands. Few people realise the real costs of supplying power for just a few hours of peak demand.

### … but ‘peaky’ consumers will not volunteer to pay

Network benefits will only be realised if a sufficient number of consumers adapt the pattern and timing of their electricity use, or pay the true cost-reflective price for their consumption during peak times. Thus, the scale of demand management is particularly important. Allowing consumers to ‘volunteer’ to face the true costs of their consumption is likely to lead to a low uptake and a low level of consumption response.

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| --- |
| Box 9.4 Behavioural traits would not preclude cost-reflective pricing |
| While price signals guide many aspects of consumption and production in advanced economies such as Australia, it is sometimes asserted in debates about electricity market reform that consumers either would not or could not respond to time-based tariffs and adapt the timing of their power use. These arguments rest on the perceived pervasiveness and effects of cognitive limitations and behavioral biases among consumers, including:   * the suggested limited capacity of consumers to digest pricing information * ‘status quo’ bias related to the familiarity of consumers with flat price structures * consumer preferences for certainty and valuing loss aversion more than seeking opportunities for savings * consumer time preferences, including a bias against immediate costs even if these may be outweighed by future benefits. (For example, smart meters represent an immediate cost, while savings from reduced supply-side capacity are realised in the medium to long term.) (Ofgem 2011)   The Commission has examined cognitive limitations and behavioural biases in several settings (for example, PC 1999, 2008, 2010, 2012a). Many, if not all, consumers exhibit some of these traits, which may have implications for appropriate implementation of demand management initiatives such as time-based pricing.  However, the Commission considers that they would not preclude responses to time‑based pricing by most consumers. Consumers already interact with various forms of dynamic or time-based pricing. That includes purchasing airline tickets, renting cars, parking in a major city, purchasing seasonal fruit and vegetables, and driving across Sydney Harbour Bridge.  Moreover, for time-based pricing to be effective does not require that all consumers adjust their behaviour. For example, for some consumers, an apparent lack of interest in new forms of pricing is likely to reflect that electricity is a relatively low share of their budget. Some of these consumers may well be willing to ‘tolerate’ higher prices than undertake the effort needed to reduce their consumption. For many households, including many of those on low incomes for which the cost of electricity is a significantly higher proportion of their overall expenditure, the opportunity to save money by shifting the timing of their consumption (and no longer cross subsidise the peaky use of other consumers) might be an attractive proposition.  Most importantly, the empirical evidence demonstrates that whatever people’s behavioural biases, they *do* reduce energy use in response to time-based pricing (box 9.3). |
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Those consumers who are initially worse off due to being exposed to the real costs of their consumption patterns would have an option (and incentive) to shift the timing of their use and take advantage of much cheaper non-peak prices. Importantly, given the direction of cross-subsidisation between consumers, more cost-reflective pricing would be likely to benefit many lower income consumers.[[19]](#footnote-19)

Given the above principles, broader application of time-based cost-reflective network pricing is central to informing consumers about the actual costs arising from their consumption patterns, and the benefits of changing those patterns, including motivating their participation in load control options. In its absence, individual consumers have limited choice about ways to lower their electricity bills, apart from reducing overall demand, which does little to help reduce peak demand. Although not all consumers would immediately embrace time-based network pricing, most parties, including the AER, accept these principles:

The AER considers effective price signalling to be a necessary feature of any market that seeks to enable behavioural change by empowering participants to make efficient decisions. Further, by making visible the true value of the costs of energy, they provide a mechanism for participants to obtain benefits from facilitating peak demand reductions, and negotiate in an informed manner. (AER 2012d, p. 3)

## 9.5 Demand management is not widely implemented

### Current prices are inefficient

Although demand management offers significant scope to address the peak load problem, at present it is not widely implemented. Rather, in contrast to most markets, in which consumers bear the costs of their consumption, in the electricity market, the substantial additional costs of meeting peak demand are not recovered from consumption at peak times.

#### Most households face inefficient prices

For most residential users, the network tariff charged to their retailer by the distributor comprises a fixed component (an access charge) and a (usually flat) price per unit of consumption (box 9.5). Irrespective of the cost of supplying network capacity at different times, the consumption-based charges are either an average (flat) price or an increasing price for consumption blocks. Such smoothing (or complete flattening) of prices encourages over-consumption at peak times (and under-consumption at non-peak times), drives inefficient supply side investment to meet that over-consumption, and results in network prices being higher on average than they need to be over the longer term.

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| --- |
| Box 9.5 What costs are included in the price of electricity? |
| The price of electricity that is visible to an end-user incorporates charges for:   * network services, including metering * energy and risk management costs from the wholesale electricity (contracts) market * a retail margin, including for billing services.   An electricity retailer recovers all of these charges from end-users and, depending on customer preferences and market (and regulatory) outcomes, they may smooth some (or all) of the variability in these charges on a customer’s behalf.  Network costs are passed from a distributor to an end-user’s retailer. Since most transmission and distribution businesses apply network charges that are flat (do not vary with time), retailers simply pass-through these costs in a time invariant manner to their customers. |
|  |
|  |

Welfare losses from flat pricing have long been identified, with economist Marcel Boiteux noting the peak load problem from inefficient flat tariffs in 1949. However, the legacy of traditional accumulation meters to measure electricity consumption for most households has meant that such inefficient pricing has largely been unavoidable. To avoid this, meters must measure consumption on a near real time basis. And, as discussed in chapter 10, while the enabling technology — smart meters — are available in much of Victoria, policy decisions have so far prevented their use for efficient pricing.[[20]](#footnote-20)

In other states, a relatively small number of households now have more sophisticated metering installed and many of these customers face (untargeted) ‘time-of-use’ (TOU) network tariffs. (For example, Ausgrid anticipates 400 000 residential users will face a TOU network tariff by mid-2013.) However, the structure of the tariff is likely to have only a minimal impact on peak consumption (figure 9.8 shown later). This is because ‘peak’ periods are usually set as a routine six to seven hour window in the afternoon and evening of weekdays,[[21]](#footnote-21) which does not reflect the relatively few hours (say 40 hours) each year when network capacity is most stretched.

Most network businesses have undertaken trials of more cost-reflective pricing structures, including of critical peak prices. Reductions in peak electricity demand during these trials have typically ranged from around 20–40 per cent.

#### Prices for businesses capture (some) wholesale energy price variation, but rarely reflect peak network costs

Nearly all large commercial premises have a smart meter installed to enable time-based pricing. Despite this, network charges generally fall short of being cost-reflective, with only a small share of businesses facing much higher charges at peak times.

While the cost-reflective (time-based) pricing of network use for business customers is weak overall, an exception is the critical peak pricing recently adopted by Victorian distributor, SP AusNet. Its business customers have faced such tariffs since 2010‑11, which apply to a four-hour window on no more than five declared critical event days. The demand effects can be large. For example, SP Ausnet introduced a cost-reflective tariff, including a critical peak price, for commercial and industrial customers consuming more than 160 MWh per year (around 1800 customers). Around two-thirds of the 1800 customers responded by reducing demand, of which 300 reduced peak demand by more than 50 per cent, and 75 by more than 90 per cent (Futura 2011, p. 47). However, the timing of the ‘critical peak’ was applied universally across the SP AusNet network and, hence, did not necessarily target the timing of more localised network constraints.

Given the general lack of cost-reflective network charges, business users have no (or little) incentive to reduce their consumption during network peaks. This contrasts to the variation in wholesale energy costs that large commercial and industrial users can face, unless they take steps to reduce their effective exposure.

The retail market is highly competitive for business users willing to accept retail offers that pass-through some variability in wholesale energy costs. Some large industrial users accept nearly full pass-through of spot market prices, preferring to curtail their use or operate standby generation if prices exceed a nominated threshold. In exchange for agreeing to face greater price volatility, such businesses receive a cheaper price for their load under non-peak conditions. Some businesses will manage price risks using sophisticated energy management systems and internal expertise, or by contracting with generators; others prefer to allow an aggregator of demand management services to assist with the development of demand response solutions.

### Uptake of non-price demand management

Under the National Electricity Rules, network businesses are required to assess demand management solutions as a means to cost-effectively defer planned network augmentation projects (sometimes referred to as ‘non‑network alternatives’).

Investigation of demand management options by network businesses draws on information about spatial peak demand at each zone and sub-transmission substation, the characteristics of the load (including the timing of peaks), the configuration of the network and the customer mix. Detailed load flow analysis is then used to identify a target reduction in peak demand that could defer a network augmentation.

Network businesses investigate various demand management solutions (box 9.6). The most feasible solution often depends on the location of a constraint in the network. The Commission understands that where demand management has been evaluated for its potential to defer a capacity driven augmentation, 75 per cent of the network expenditure that would have been required in the absence of demand management has been for zone substations and 11 kV distribution feeders (Ausgrid, pers. comm., 2012).

Despite the efforts of network businesses to pursue demand management to delay network investment, in practice very few projects have been assessed as viable. For example, Ausgrid performed 86 demand management screening tests over a period of three years, but found that only 10 projects were viable (counting only the short‑term benefits of network deferral) (table 9.2).

Table 9.2 Very few non-network solutions are implemented

Ausgrid

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
|  |  | 2008‑09 | 2009‑10 | 2010‑11 |
| Screening tests | No. | 42 | 26 | 18 |
| Investigations | No. | 9 | 6 | 3 |
| Projects authorised | No. | 5 | 3 | 2 |
| Project cost a | $ million | 3.95 | 2.75 | 1.37 |
| Project savings from deferral a | $ million | 13.40 | 6.46 | 4.17 |
| Proportion of augmentation capital allowance | Per cent | 3.60 | 1.30 | 0.70 |

a Of implemented projects.

*Source*: Ausgrid (2011c, p. 12).

|  |
| --- |
| Box 9.6 Demand management options considered by network businesses |
| Demand management options considered by network businesses often involve:   * contracting with existing standby generation installations * negotiating with commercial and industrial users to contract a quantity of peak demand reduction that can be called upon when required. For example, electricity demand in Tasmania is dominated by four large industrial businesses (ESIEP 2012a), with whom agreements can be reached (usually at low cost compared with smaller users) to curtail their use of system capacity upon request[[22]](#footnote-22) * deploying temporary (modular diesel-fuelled) generators at suitable sites in the network requiring reduced demand on 11 kV feeders and zone substations. Network businesses usually lease such generators under tender arrangement, with each 5 MVA module costing around $1.25 million per season plus hourly operational and maintenance costs of $2000 * residential load control of air conditioning and pool pumps. There have been extensive trials of load control of such appliances that have demonstrated their technical feasibility, consumer receptiveness to control and the degree of demand response. Results from the trials suggest that a major reduction in the normal peak operating load of air conditioners may be achievable — equivalent to 20–30 per cent reduction in the peak demand of the trial households (Futura 2011, p. 60). Some network businesses are now introducing direct load control options into their customer offerings. For example, in Queensland, Energex is currently subsidising the installation of air conditioners whose power can be capped at times of network congestion (chapter 10) * commercial building energy efficiency programs. Cost-effective options usually target lighting upgrades. A previous project by EnergyAustralia offered businesses around $200/kVA for demand reductions, but when all expenses were included the cost of the project was $115 000, hence costing $450/kVA. |
| *Sources*: EnergyAustralia and TransGrid (2009); ESIEP (2012a); Futura (2011). |
|  |

Demand aggregators can step in to arrange contracts with end-users and assist with identifying and implementing cost-effective load reduction options on behalf of networks. A particular feature of such arrangements is that the aggregator takes on the risk of a demand management solution not meeting the agreed reduction in demand.[[23]](#footnote-23) Demand aggregators tend to target load reductions from large business users, as the costs of negotiating and setting up an individual arrangement with end users (including ‘site enablement’ and real time monitoring capability) typically amounts to thousands of dollars per site. Consequently, five-year contracts are normally established with end-users.

A one-off survey in 2010 of Electricity Network Demand Management in Australia found that, in 2010‑11, demand management by network businesses was expected to displace 0.8 per cent of the total peak demand (equivalent to 367 MW, and more than four times higher than in 2008‑09) (Dunstan et al. 2011a, p. vi).

Futura Consulting recently sought to quantify the volume of peak demand management in the NEM (2011). They found approximately 430 MW of peak demand reduction was sourced from commercial and industrial customers,[[24]](#footnote-24) which is equivalent to around 1 per cent of system peak demand in the NEM. Similarly, an annual survey undertaken by AEMO of demand management by retailers, network businesses and demand response aggregators indicates that the level of demand response amounts to less than 1.5 per cent of the NEM-wide peak (table 9.3; AEMO 2012a).[[25]](#footnote-25) This level appears low compared with international benchmarks. For example, in California the equivalent peak load reduction is 6 per cent (Faruqui and Fox‑Penner 2011, p. 46).

Table 9.3 **Levels of demand response from all reported sources**

Aggregate energy consumption (MW) by likelihood of businesses participating in demand management for the 2012‑13 summer

|  |  |  |  |
| --- | --- | --- | --- |
|  | Very likely | Even chance | Very unlikely |
| Queensland | 78 | 111 | 111 |
| New South Wales | 31 | 71 | 98 |
| Victoria and South Australia | 109 | 121 | 149 |

*Source:* AEMO (2012a, p. D-2).

While the survey is intended to capture the demand management activity of retailers, evidence of substantial load shedding following wholesale market price spikes suggests the survey underestimates actual demand management activity of their customers. For example, investigations by the AER reveal the following price spikes in the spot market in New South Wales:

* during a period of high temperatures, around 500 MW was shed in November 2009, following a price spike to $6200/MWh (Futura 2011, p. 43)
* an episode of disorderly bidding (chapter 18) by generators on 4 February 2010 resulted in prices varying from $10 000/MWh to the market floor price (‑$1000/MWh) and 538 MW of load being shed over the space of just one hour (AER 2010d).

These examples demonstrate the willingness of some industrial businesses to respond to commercial incentives for load management. Depending on the size of the payment, such end-users would require to curtail their load (or price they would be willing to avoid), this evidence suggests a greater source of demand response capacity for networks to tap into.

## 9.6 Why is the uptake of demand management so low?

Despite the conceptual appeal and stated potential for wider implementation of demand management, there has been a low level of uptake across the NEM (particularly by network businesses). This is likely to reflect several factors, including:

* the absence of interval meters — and particularly remotely-read or smart meters — for the majority of residential households. There is likely to be underinvestment in smart meters to the extent the benefits are ‘split’ along the supply chain and some regulatory arrangements act as barriers to their installation (chapter 10)
* where smart meters are available for residential customers, their use for demand management may be restricted. For example, although smart meters have been installed across Victoria, the state government imposed a moratorium on their effective use for time-based pricing until mid-2013 (chapters 10 and 11)
* the National Electricity Rules (and their application by the AER) may, in some cases, have the unintended effect of limiting the incentives of distribution businesses to implement demand management solutions, even where they offer the most efficient solution (AEMC 2012u) (chapters 5,10 and 12)
* distribution businesses are concerned about the risks of implementing demand management, given their unfamiliarity with the techniques and the added complexity to their business model. For example, Ausgrid suggests that a decision to engage demand management:

… leaves the network operator with at best a marginal benefit until the next regulatory reset in exchange for a higher risk profile and more complex business model. … In this environment there is little incentive for such businesses to be innovative, or assiduous in finding and securing [Demand Side Participation]. (Ausgrid 2011c, pp. 11‑12)

* the perception that customers will not respond to prices or other market-based incentives to shift loads. This assumption is not supported by trial evidence, which shows consumers do shift or curtail their peak consumption in response to price incentives (box 9.3). The current lack of price signals limits consumers’ understanding about the costs of their consumption and the potential to benefit from economising, where feasible, at peak times
* retailers lack financial incentives to implement demand management. Indeed they currently have (particularly the ‘gentailers’) a financial disincentive to do so. Moreover, market imperfections, created by retail price regulation in most of the NEM, stymie more innovative business pricing models (chapter 12). These factors introduce uncertainty around whether retailers will pass on cost-reflective network charges
* a lack of coherent evidence to inform what constitutes a socially efficient level of demand management. Specifically, evidence from pricing trials (including elasticities) has not always been made publicly available, despite the clear benefits from a broader base of knowledge to construct more cost-reflective tariffs
* the impact of deterministic reliability regulations for networks may dampen any appetite for demand management (chapter 15)
* some technologies to implement demand management, including battery storage and distributed generation, are not yet commercially viable (chapter 13).

These issues are evaluated more specifically in later chapters and, while some have important implications for the way a demand management approach such as cost‑reflective pricing might be implemented, in the Commission’s assessment they should not necessarily preclude the use of such an approach.

Before embarking on an assessment of specific solutions to address the potential barriers to the wider uptake of demand management, it is important to know that the potential net benefits are material. To this end, the following section evaluates, more systematically, past reviews and recent evidence from trials and experiments on the costs and benefits of demand management.

## 9.7 Gauging the prospective benefits and costs of demand management

As noted in section 9.1, growth in peak demand is likely to necessitate potentially billions of dollars of network investment, for which consumers ultimately pay.

Demand management thus offers the potential for significant benefits, including:

* in the short to medium run, investment savings from delaying or removing the need to augment network capacity
* in the long run, a more efficient electricity system — where expansion of peak capacity only occurs to the extent that consumers are willing to pay for it.

However, implementing demand management solutions (especially at a household level) brings its own costs and difficulties. The main costs of demand management are:

* the costs of implementing any scheme — including the costs of smart meters, customer education and business transition costs, such as costs to retailers and network businesses associated with information technology (IT) and other technology investments
* any perceived loss in consumers’ wellbeing from exposure to cost-reflective prices.

Demand management initiatives should be pursued only if it is likely that their implementation will yield benefits in excess of their costs. Such assessments ultimately need to be made on an initiative-by-initiative basis, taking into account localised considerations and different implementation strategies that may affect the present value of the stream of benefits and costs entailed. Complementarities that may occur between different initiatives would also need to be considered. For example, smart meters and time-based pricing can be adopted in tandem with the option of direct load control of appliances, which can support consumers’ acceptance of new pricing approaches and achieve a more reliable demand response.

A number of studies have examined the benefits and costs of demand management (CRA 2006, 2008a, 2008b; Deloitte 2011a; EMCa 2008; ESC 2002, 2004a; KPMG 2008; NERA 2008a, 2008b). By revisiting these studies and drawing on new information, particularly from the rollout of smart meters in Victoria, the Commission has sought to gauge the prospective gains from the further adoption of demand management in Australia. As an input into the assessments of specific initiatives in later chapters, it also aims to:

* identify information that could be pivotal in approving specific demand management projects
* highlight gaps in current knowledge of relevant costs and benefits
* draw out implications for the implementation path of the recommendations.

To those ends, the Commission has compiled indicative estimates for a number of demand management initiatives.[[26]](#footnote-26) The analysis incorporates estimates of untargeted ‘time-of-use’ pricing, direct load control and critical peak pricing. Sensitivity analysis is included to reflect uncertainties around key components of the estimates.

The following subsections summarise the key findings from the analysis.

### Some demand management options offer substantial benefits

The Commission’s calculations suggest that the net benefits of demand management depend crucially on the manner in which demand management is implemented (with indicative estimates of the outcomes shown in table 9.4).

* If a smart meter rollout is implemented efficiently and targeted at regions where capacity constraints are impending, then the relevant households could get a stream of benefits that add to around $900–$1900 per household in net present value terms. This stream of benefits is equivalent to an *annual* benefit of around $100‑$200 over the life of the meters.[[27]](#footnote-27) The benefits arise mainly from deferring network augmentation (as discussed further below) and from savings in the operating costs of networks (such as remote reading of meters and fault detection).
* There is a substantial risk that a fast-tracked NEM-wide smart meter rollout would impose net costs. This reflects that an immediate national smart meter rollout would involve high upfront costs, but limited savings from deferred network augmentation in the many areas where there are no immediate network constraints.
* A meter rollout combined with weakly targeted time-of-use tariffs would fail to generate a significant demand response, so that most of the benefits of a rollout would be derived from savings in remote meter reading and other network operating costs, rather than deferring network investments. The most likely outcome would be a net cost.
* Implementation of direct load control of air conditioning is likely to produce significant net benefits, though the pace of adoption of this technology depends on the share of new air conditioners with an in-built compatibility with direct load control.

The results highlight the importance of a more targeted approach to where and when investments in smart meters (or other demand technologies) occur.

Table 9.4 Relative merits of stylised demand management approaches

Benefit–cost ratios, indicative estimatesa

|  |  |  |  |
| --- | --- | --- | --- |
| Scenario | Low | Mid-point | High |
| National smart meter rollout with critical peak pricing | 0.6 | 1.2 | 2.7 |
| National smart meter rollout with untargeted time of use pricing | 0.3 | 0.6 | 1.1 |
| Direct load control in the absence of smart meters | 1.2 | 2.7 | 6.3 |
| Smart meter rollout in areas with network constraints, accompanied by critical peak pricing | 1.1 | 2.7 | 6.9 |

a A benefit–cost ratio less than one implies that the stream of discounted costs was more than the stream of discounted benefits. The low case for most scenarios is below one, indicating a risk of a net cost. If a scenario has higher benefit–cost ratios in all cases, it is more likely that the scenario would be of net benefit. However, a more risky project may be warranted if benefits can be obtained across a larger proportion of peak consumption — such a scenario is more likely to warrant additional efforts to mitigate the potential for downside risks.

*Source*: Commission estimates from the technical supplement on the costs and benefits of demand management.

As discussed at length in the technical supplement, there are uncertainties about the magnitude of the costs or benefits attached to some of the key components of the estimates in table 9.4. Over time, and with iterative experiences in implementing demand management approaches, it should be possible to identify a narrower range of estimates. These uncertainties also imply that a one-off decision for a mandatory rollout of smart meters in a given period across a whole state (as occurred in Victoria) should be avoided. Such a universal rollout loses the option value of waiting for new information about costs and benefits, and from determining the best sequencing and location of meter rollouts. Chapter 10 discusses the appropriate regulatory arrangements to maximise the net benefits of smart metering rollouts.

As discussed earlier, there is further scope for gains from the nearer-term adoption of more efficient time-based network pricing for commercial and industrial end-users, which the Commission has not modelled.

### Avoiding or deferring network augmentation yields significant benefits

Reducing the growth in peak demand can ameliorate the need for additional investment. There are significant costs involved in providing capacity to supply peak demand. As such, any (reliable) reduction in peak demand growth may give rise to significant investment savings. The Commission reviewed many estimates of the long-run marginal cost of delivering an additional kW to an end user during critical peak periods[[28]](#footnote-28) and found the following ranges plausible:

* $150–$220 of distribution infrastructure costs for an additional kW per year
* $30–$70 of additional generation capacity costs for an additional kW per year
* $90 of transmission infrastructure costs for an additional kW per year.

This suggests that, in aggregate, the long-run marginal cost of adding the capacity to deliver power to consumers at critical peak times is likely to be somewhere in the range of $270–$380 per kW per year.

While growth in peak electricity consumption is a critical driver of network augmentation, parts of the network will have differing levels of spare capacity. The potential for benefits from introducing demand management is likely to be highest in parts of the distribution and transmission network where electricity consumption during critical peak periods is reaching capacity. However, such benefits can only be realised if demand management can sufficiently temper the growth in critical peak consumption to defer or negate the need to augment the network.

### Not all forms of demand management are effective at reducing peaks

In Australia, a number of demand management schemes have been trialled or introduced. They have included untargeted TOU pricing (unrelated to peak events), critical peak pricing (or rebates for curtailing electricity consumption during critical peak events) and the use of direct load control technology (also targeting critical peak events).

The reduction in energy use during critical peak events has been substantially lower under untargeted TOU schemes than under other demand management schemes (figure 9.8). Untargeted TOU charging is less effective than other demand management approaches because:

* the price variations between ‘peak’, ‘shoulder’ and ‘off-peak’ times are relatively shallow
* the peak periods are relatively long (typically applying for 1000–1600 hours per year) and do not target critical peaks (typically 40‑80 hours a year)
* while TOU prices and periods may change during the year — reflecting seasonal patterns of demand — they usually do not change more than twice a year.

Figure 9.8 Reduction in peak electricity use for Australian trials

Per cent reduction in peak electricity use, by type of demand management

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*Data source*: Futura (2011).

The likely scale of reduced peak energy use from a wider rollout of demand management in Australia may be smaller than that achieved through trials. For example, some trials have restricted eligibility to consumers that have greater scope to reduce peak energy use (for example, households with air conditioners) or have a disproportionate number of participants who are interested in energy conservation (Futura 2011; Graham Palmer, sub. DR46, p. 2). In addition, trials intensively educated participants, provided technologies to assist participants monitor their power use, and some even funded or subsidised the purchase of more energy efficient appliances. Therefore, lower reductions in peak energy use may be achieved outside of trial settings.

### Smart meters are a crucial cost item

Implementing sophisticated demand management requires new infrastructure of its own (chapter 10). Smart meter infrastructure is already in place for large commercial and industrial users, and therefore there is no physical barrier to the utilisation of greater demand management techniques for these users. In contrast, for the residential and small business customers in the NEM currently using traditional ‘accumulation’ meters (box 10.1 in chapter 10) the transition costs to adopt smart meters can be significant.[[29]](#footnote-29)

In Victoria, the rollout cost around $800 per meter, with further ongoing operating costs of $20–30 per year.[[30]](#footnote-30) This is greater than the ‘building block’ forecasts produced by Energy Marketing Consulting associates (EMCa 2008), which suggested costs of under $500 per meter. While the EMCa report appears to have underestimated the complexities of a rollout, in particular in project management and IT, the market for smart meters is maturing and prices are declining. The cost of rolling out smart meters in future should be lower than the Victorian experience. However, the extent to which smart meter prices may fall is uncertain.

### *Smart meters would provide other benefits*

A smart meter rollout also offers the potential to deliver other benefits that are largely unrelated to demand management (Deloitte 2011a, pp. 58‑66, 73‑80). While the list of other benefits is long, they include improvements in network management and efficiency, such as:

* manual reading of accumulation meters should not be required
* disconnections and reconnections and of special meter reading (such as when consumers dispute their bills) can be conducted remotely
* networks can detect outages almost immediately, and faults can be diagnosed more rapidly, allowing them to respond more quickly and cost effectively.

Recent Australian studies provide varying estimates of these other benefits (CRA 2008a; Deloitte 2011a; Futura 2009; NERA 2008b; Oakley Greenwood 2010b). The most recent of these studies (Deloitte’s analysis of Victoria’s smart meter rollout) indicates that these other benefits can exceed those derived from innovative tariffs and demand management (AEMC 2012d, p. 8).

However, these estimates are for a mandated system-wide rollout. The Commission’s approach would encourage localised rollouts that target areas where the network is approaching capacity and, where otherwise, network augmentations would occur. Under these circumstances, the benefits from deferred network augmentation would be realised relatively quickly. In contrast, under a mandated rollout, many regions would have significant spare capacity, so that there would often be no immediate potential for deferring investment. Under the Commission’s approach, bringing forward these deferral benefits increases their net present value and, commensurately, reduces the proportion of the total net present value of benefits derived from other benefits (box 9.7).

### Summing up

The Commission’s analysis suggests that demand management has the potential of delivering significant benefits, but that the magnitude of the net benefits attainable in practice depends on the particular initiatives adopted and the way in which implementation occurs.

Inevitably, there remains uncertainty about the precise magnitude of some of the costs and benefits, for example in relation to smart meters (and all the associated costs of their full implementation), which are critical for effective demand management. Most evidence suggests that the costs in the Victorian rollout were higher than anticipated, and their effective use has not yet been realised. Nevertheless, the capital costs of smart meters will fall over time, making demand management schemes progressively more viable. The benefits from deferring network expansion will be pivotal in determining the viability of rolling out many demand management schemes.

Ultimately, realising the potential benefits of demand management relies on a sufficient number of electricity users responding to price signals and adapting their consumption habits, and doing so in a timely manner. Accordingly, it is essential that consumers are appropriately supported in adjusting to new pricing approaches, especially to avoid a prolonged transition that would forego the main benefits of pricing reform in the medium term and jeopardise the cost-effectiveness of smart meter investments.

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| Box 9.7 Timing of benefits differ for mandated and targeted rollouts |
| The benefits of a smart meter rollout can be categorised into four broad areas:   * benefits generated by innovative tariffs and demand management * avoided costs associated with accumulation meters resulting from the rollout * benefits derived from efficiencies in network operations * other minor efficiencies in network and retail operations.   Deloitte (2011a) estimated the mix and timing of benefits for Victoria’s mandated rollout of smart meters (see figure below). This figure shows that the benefits from innovative tariffs and demand management take time to emerge fully, whereas benefits from, for example, avoided costs of meter reading and from more efficient network operations are realised from at or near the start of any rollout.  Estimated value of Victorian rollout benefits over 2008–28  Net present value, 2008 prices  Box 9.7 Figure 1 Estimated value of Victorian rollout benefits over 2008-28. This chart shows the estimated monetary value of benefits from the Victorian smart meter rollout.  By comparison, a localised rollout that targeted areas where the network is at, or approaching, capacity could be expected to realise the benefits of deferred network augmentation in the early years of the rollout rather than later, which would be the overall result under a mandated rollout. In terms of the figure above, this would have the implication that the contribution of innovative tariffs and demand management to the overall benefits would be closer to that shown for 2028. |
| *Source*: Deloitte (2011a, pp. 58, 83). |
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1. The most common way of quantifying peak demand is to compare the maximum quantity of electricity consumed to the average quantity consumed. This measure allows the comparison of peak consumption in different regions and over time. Network operators have started to put in place a number of demand management schemes — at this stage, mainly confined to business users — based around ‘critical peak events’. These critical peak events typically occur for around 40–80 hours per year. [↑](#footnote-ref-1)
2. With hedging arrangements or contracts with generators, even these pricing signals may be muted. [↑](#footnote-ref-2)
3. For example, with some network configurations, it may be possible to shift loads between adjacent substation areas, so that congestion at one substation can be relieved by transferring load to an unconstrained substation. [↑](#footnote-ref-3)
4. Smart meters can allow both distribution businesses and retailers to implement demand management, addressing network and wholesale peaks respectively. [↑](#footnote-ref-4)
5. A large investment will have a high annual deferral value. [↑](#footnote-ref-5)
6. An exception is when the security of the NEM is under threat due to an imbalance between available supply capacity and demand at any instant, which can call for shedding of a threshold volume of load to prevent system failure. [↑](#footnote-ref-6)
7. The particular effect of rising income on the rate of peak demand growth is described as a paradox, since the associated increases in electricity costs may actually cause ‘fuel poverty’ (Simshauser and Nelson 2012). [↑](#footnote-ref-7)
8. In this chapter, ‘time of use’ charging schemes refer to where consumers are charged a higher price for electricity consumed for fixed periods every week day — not just during peak demand periods. [↑](#footnote-ref-8)
9. The average size of new dwellings is increasing rapidly. From 1986 to 2020, the total floor area of residential dwellings is expected to increase by 280 per cent (DEWHA 2008, p. x). [↑](#footnote-ref-9)
10. There is no comprehensive data on the vintage of the current stock of air conditioners but, based on survey samples, the average age may be around six years (Galaxy Research 2012). However, a move to more cost-reflective prices would provide a strong incentive for consumers to choose more energy efficient appliances when their air conditioners reach the end of their life and need replacing. The type of appliance is also relevant. Most households operate split-system (non-ducted) reverse cycle types, which have lower energy efficiency than an evaporative cooler (Graham Palmer, sub. DR46, p. 2). Only around 5–6 per cent of new air conditioning sales are for the more energy efficient evaporative systems, although these are not suited to all climates. [↑](#footnote-ref-10)
11. The $7000 cost is derived from Energex estimates (Queensland Department of Employment, Economic Development and Innovation 2011, p. 4), which indicate that the costs of adding 1 kW of capacity (including all network and generation costs) is around $3500 for the life of the network and generation assets. (The Commission cites a wider range of figures later in this chapter.) However, the life of an air conditioner is considerably shorter than the life of the assets supplying additional capacity, and so it is incorrect to attribute all of the capacity charges to a single air conditioner. [↑](#footnote-ref-11)
12. Modelling undertaken by Charles River Associates for Endeavour Energy using a long run marginal cost approach for capital investment to meet peak demand indicates that the cross‑subsidy between customers with air conditioning and those without is $80–$110 million per year — or approximately one third of total sales to the residential and small business sectors. If this subsidy is smeared across all of the remaining consumption by these groups it equates to 1.5 cents/kWh to 2.0 cents/kWh relative to the marginal rate (Endeavour Energy 2012b, p. 43). Based on an average household consumption of 7500 KWh pa (Simshauser 2012), this range represents around $112–$150 per annum. [↑](#footnote-ref-12)
13. The literature does not adopt a consistent nomenclature. In this report, demand side management is used interchangeably with demand response, but generally excludes energy efficiency and energy conservation programs (that tend not to be ‘peak’ focused). [↑](#footnote-ref-13)
14. Stemming the rate of peak demand growth can delay the timing of a network augmentation (increase in capacity). Further, for some less ‘lumpy’ assets (where scale economies are a less significant driver of costs), a lower rate of peak demand growth can also reduce the size of the investment, particularly in less densely populated rural and remote areas. [↑](#footnote-ref-14)
15. The extent of many of the other benefits listed is uncertain and would be difficult to quantify with precision. Further, some would be secondary to the thrust of policy and regulatory changes covered in this report. For example, demand management measures targeting network peaks could incidentally improve generation market outcomes. [↑](#footnote-ref-15)
16. For the purpose of reducing peak consumption, the cost of implementing energy efficiency options will typically outweigh the network savings. Nevertheless, some energy efficiency measures can assist consumers to shift the timing of their electricity use — for example, the insulation of dwellings can allow cool air to be ‘stored’ prior to a peak period of consumption. [↑](#footnote-ref-16)
17. The price responsiveness of commercial and industrial use varies widely, largely driven by production characteristics of the business and the contribution of electricity to business costs. [↑](#footnote-ref-17)
18. Not all trials find a declining marginal response as prices increase. For example, the Illinois Energy-Smart Pricing Plan found a price elasticity of −0.047 when the price was below $0.13/kWh, but −0.082 when it was above (Summit Blue Consulting 2006). [↑](#footnote-ref-18)
19. Studies of time dependent pricing generally find that low income groups are no worse off, and usually tend to be better off (AEMC 2012d; volume 2 of Deloitte 2011b, p. 109). [↑](#footnote-ref-19)
20. Such meters can usually communicate prices in half hourly intervals, although in practice consumers could probably not efficiently respond to that frequency of price movements. [↑](#footnote-ref-20)
21. Sometimes defined over a 15 hour period of each weekday. [↑](#footnote-ref-21)
22. Industrial customers account for around 60 per cent of Tasmania’s total electricity consumption, with four major industrial customers using around half of the energy supplied by the Tasmanian power system. Under the System Protection Scheme, load shedding by industrial customers occurs instantly in the event of an unplanned outage of Basslink while energy is flowing into Tasmania. [↑](#footnote-ref-22)
23. To manage this risk, aggregators (such as EnerNOC) usually over-contract the required demand reduction with end-users and closely monitor or remotely control their load. To the extent that an end user retains ultimate control over their load, an aggregator ‘coaches’ them to ensure they perform as expected when a reduction in load is to be dispatched. [↑](#footnote-ref-23)
24. Including curtailable load arrangements, dynamic peak pricing and the use of standby generation. [↑](#footnote-ref-24)
25. This level represents the full amount of the ‘very likely’ demand response and 50 per cent of the ‘even chance’ demand response, as a proportion of the maximum demand for each jurisdiction. [↑](#footnote-ref-25)
26. These are contained in the Commission’s technical supplement on the costs and benefits of demand management. This supplement is available on the Commission’s inquiry website. [↑](#footnote-ref-26)
27. While not enumerating the household benefits of particular demand management initiatives, the AEMC (2012u, p. 259) found significant savings from what appear to be achievable reductions in peak demand. It estimated that for a typical average annual consumption level of 8 MWh and retail bill of $2000, reductions in peak consumption of around 14 per cent to 18 per cent of original usage during the peak period (between 2 pm and 8 pm) would achieve savings of around $200 on an annual bill. The present value of this saving is around $2500 per household). [↑](#footnote-ref-27)
28. The information was obtained from personal communications with various network businesses; network business pricing proposals; Futura (2009); Oakley Greenwood (2010b); Deloitte (2012), and the Queensland Department of Employment, Economic Development and Innovation (2011). [↑](#footnote-ref-28)
29. While consumption could be metered in half-hour increments by a simple ‘interval meter’ (an approach taken by Ausgrid), this would not provide timely feedback to customers about their power use, or any of the other benefits provided by smart meters. [↑](#footnote-ref-29)
30. This compares with the replacement cost of an accumulation meter of around $170 (this covers the cost of the meter and the cost of installing the meter) (AEMC 2012y, p. 2). [↑](#footnote-ref-30)