11 Moving to time-based pricing for the distribution network

|  |
| --- |
| Key points |
| * Under current pricing approaches, households and many businesses are not exposed to the much higher costs of supplying electricity during critical peak periods. * This increases consumption of power during peaks, increasing the need for network investment, and pushing up average prices. Current pricing approaches also mean that those who use electricity less at peak times (often low-income consumers) subsidise those who use electricity more at peak times. * The broad case for moving to cost-reflective, ‘time-based’, pricing for distribution network services is strong. As its use for some larger businesses exemplifies, it is practically feasible, with smart meters providing the technical means to extend the approach to households. Moreover, the pay-offs from doing so are potentially significant. * However, there are many complexities and challenges in giving practical effect to such time-based pricing. A coherent, iterative and consultative implementation process that harnesses the knowledge of those at the coalface is required. * While not seeking to prescribe the pricing regimes that should emerge from this process, the Commission expects that network prices would be low for most hours of the day, but ramp up significantly during defined periods for critical peak demand events (such as a heatwave). The Commission supports the AEMC’s proposal that people can opt into cost-reflective tariffs, or choose to remain on a flat tariff (that would then rise over time as non-peaky users selected cost-reflective prices). * Such changes would not give distribution businesses carte blanche to gouge consumers. Distribution network service providers would each be subject to an overall revenue cap. * Given the broad end point is clear, but the means and timeframes for getting there less so, the Commission has focused on ways to help ensure that there is an effective implementation process and conducive regulatory framework. It recommends: * the Standing Council on Energy and Resources oversee and drive the process * some supporting changes be made to licensing arrangements for network providers and the National Electricity Rules * specific arrangements be employed to provide targeted assistance to vulnerable consumers adversely affected by the change in pricing approach * distribution businesses and energy retailers be required to demonstrate that they have engaged appropriately with their customers about the changes. |
|  |

## 11.1 Introduction

As discussed in previous chapters, distribution businesses must build substantial and costly network capacity for infrequent periods of peak demand. However, where customers’ electricity tariffs do not vary over time, these costs are spread across all customers, regardless of any particular customer’s actual use of the network in these peak periods. In effect, power use during peak demand periods is subsidised, while power use during non-peak periods is ‘taxed’ to fund those subsidies.

This misalignment of costs and prices has several major undesirable consequences.

* The ratio of peak to non-peak network prices would be much higher were prices cost-reflective. As discussed in chapter 9, there is compelling evidence that peak demand responds to prices. Collectively, these effects imply that fixed tariffs result in a significantly higher level of demand in peak periods. As is the case with any subsidy that stimulates demand, the value of the additional consumption during peak periods to end users is less than the (substantial) cost of meeting it — a major source of economic inefficiency. The corollary is that in non-peak periods, consumers pay above the real costs of supply, and therefore consume inefficiently low amounts of power at these times.
* Since the level of investment in networks and generation is above efficient levels (leading to higher aggregate electricity supply costs), average electricity prices are higher than they otherwise would be.
* Regardless of the degree to which peak users respond to price changes at peak times, there remains a distributional argument for introducing critical peak pricing. For example, suppose that peak demand was completely unresponsive to price changes. In that case, the required network capacity would be the same regardless of whether networks introduced critical peak pricing or not (and so the *economic inefficiency* of non-cost-reflective pricing would be small). However, with critical peak pricing, non-peaky users would no longer be subsidising peaky users. In contrast, under current flat tariffs, non-peaky users of power face excessively high prices, and cross-subsidise peak users. Often this means that low-income consumers cross-subsidise higher income consumers.

Accordingly, the broad case for embodying a cost-reflective, time-based component in prices for use of network services — and especially the distribution component of the network — is strong.[[1]](#footnote-1) This would ensure optimal network capacity at peak times, recognising that many people will want, and be willing to pay for, additional capacity for very hot or cold days. The conceptual argument has long been recognised (Joskow and Wolfram 2012). The empirical evidence from trials also suggests that once people have experienced time-based charging, most are satisfied with it.[[2]](#footnote-2) More importantly, as shown in chapter 9, the efficiency and equity pay-offs from introducing generally applicable, cost-reflective, time-based pricing — hereafter referred to simply as cost-reflective pricing — would be potentially large.

Cost-reflective pricing is feasible. It is already employed for some industrial and commercial users, as well as in various non-electricity markets where demand and/or supply costs are time sensitive. Moreover, the smart meters necessary to implement cost-reflective pricing at the household level are readily available and already in place in much of Victoria. Ausgrid has already rolled out nearly half a million interval meters in New South Wales, and has installed 16 000 smart meters, mainly as part of the Australian Government’s Smart Grid Smart City Trial (Ausgrid 2012g).

It is therefore unsurprising that many major players are supportive of removing obstacles to the use of cost-reflective pricing by networks and retailers. These include the Australian Energy Market Commission (AEMC), Major Energy Users and most peak industry bodies representing the supply chain (such as the Energy Networks Association, the Energy Retailers Association and the Energy Supply Association). Consumer groups also acknowledge the benefits, though they want the risks managed for low-income consumers.

Given that the case for a shift to cost-reflective pricing has already been made in chapter 9, this chapter concentrates on how to *practically* achieve that outcome. Implementing widespread cost-reflective pricing will involve many complexities and challenges, not the least of which is ensuring households and other consumers understand its implications and the means by which they could adjust their power use in response to it. The goal should not be to achieve the perfect scheme that accords with some textbook. Rather it should be to develop a workable, and broadly acceptable, approach that generally avoids the costs of catering for critical peak load demand that consumers would be unwilling to pay for were they to be charged genuinely cost-reflective prices.

Any reform in this area needs to take account of existing pricing practices (section 11.2) and any provisions in the National Electricity Rules (section 11.3) that may limit reform. Defining the basis for cost-reflective prices is not trivial, and requires pricing that signals where and when a business needs to expand its network — an issue examined in section 11.4. Implementing cost-reflective pricing requires a carefully sequenced set of changes including:

* institutional arrangements that will provide a continued impetus for pricing reform (section 11.5). Reform must be gradual, coordinated and involve consultation with all stakeholders, but it must also have timelines
* a National Electricity Market (NEM)-wide framework (section 11.6)
* a supporting set of regulations and guidelines (sections 11.7 and 11.8)
* the need to address affordability and equity issues, predominantly the requirement that there are well designed, targeted mechanisms in place to assist those vulnerable consumers who would be disadvantaged by the changes (section 11.9)
* the transition to cost-reflective pricing (section 11.10)
* the need to bring all the various stakeholders on board by providing assurance that the reforms would be workable and beneficial, and particularly the critical need to engage and educate consumers (section 11.11).

## 11.2 How do distribution businesses currently price?

There are multiple ways of recovering the costs of distribution network businesses (box 11.1), and their application varies by customer class. The largest industrial and commercial users often already face cost-reflective prices, and the use of such pricing is extending to other large users.

However, for most households and small and medium enterprises, costs are recovered through a fixed charge and an energy use charge. Time-based charging of any kind is mainly limited to trials. Even where there are time-varying prices for households, they usually take the form of untargeted time-of-use (TOU) tariffs. These apply ‘peak’ prices for long periods of every day, instead of targeting the few hours of critical peak demand.[[3]](#footnote-3) Given this, the ratio of off-peak and peak prices in TOU tariffs tend to be low, and accordingly, their effect on consumer behaviour also appears to be muted (Futura 2011, pp. 13‑15, p. 60). Overall, the implication is that distribution businesses recoup a high and excessive proportion of their costs from non-peak energy usage charges (AEMC 2012b, p. 21; box 11.2).

|  |
| --- |
| Box 11.1 Some terminology relevant to discussions of peak demand |
| Terminology in this area is often confusing, ambiguous or overlapping. Accordingly, the meaning behind some commonly used terms is set out below.   * *Time-based pricing/ time-dependent pricing* — terms often used interchangeably to refer to prices that vary over time. The usual time dimension is hours, but prices may also vary from season to season or from weekday to weekend. * *Cost-reflective pricing of the network* — requires that prices signal the underlying costs of supply at the time of consumption. This requires that a peak period be defined sufficiently narrowly to ensure that the costs of peak capacity are recovered from consumption driving such investment. * *Time-of-Use (TOU) tariffs* — a specific price structure where the day is divided into two to three consumption periods — ‘peak’ and ‘non-peak’ and sometimes ‘shoulder’ periods. A TOU tariff may additionally vary from season to season, depending on whether summer or winter peaks are more common. A feature of such tariffs is that the difference between peak and non-peak charges is not normally very large. This is because the ‘peak’ period tends to be very broad, with anything from 1000–3000 ‘peak’ hours over a year. The peak consumption in the NEM that drives significant additional network investment is much more short-lived — as few as 40–80 or so hours a year. Hence, the ‘peak’ price under a TOU tariff does not, by itself relate well to, or serve to reduce, the more intense peak consumption that is of concern in the NEM from a network investment perspective. * *Critical Peak Price (CPP)* — a type of peak network price applied very narrowly to signal when demand is very high and supply very tight. A CPP is applied when a distributor declares a critical peak event. Where they have been applied for industrial or commercial users, it has usually been for a two to six hour window on five to 10 days per year. To assist the demand response and to avoid ‘bill shock’, customers are normally notified the day ahead of such an event and reminded two hours prior to commencement. Where applied, CPPs have been set to reflect the full cost (see below) of meeting a customer’s peak demand. They then have an informed option of how much energy to consume during the peak. * *Peak capacity charge* — this is specific to a given customer (rather than a customer class) and usually only applies to users with high energy demands. Different networks use different methods for calculating the charge, but in each case, the charge takes account of the fact that for a network, it is the maximum requirement for power, not energy flows per se, that is a major contributor to network investment (Ausgrid 2012d, p. 55). For example, SP AusNet (2013b, p. 50) bases its capacity charge for a low-voltage business user on the nameplate rating of the transformer supplying the customer. In Ausgrid’s case, for any given customer, the charge is the maximum (the so-called ‘Billable Maximum Capacity’) over the past year of the half hourly *power* readings (in kW or kVa) from the relevant peak periods. For example, this is 2 pm to 8 pm on week days in Ausgrid’s network (2012d, pp. 52ff). In Ausgrid’s case, capacity charges require a meter that can record 30 minute interval power (Type 5 or better meters — chapter 10). * *Peak charges based on Long-Run Marginal Cost* — the components of an overall tariff that reflect the marginal network cost of supplying peak demand over a period that is sufficiently long to make all costs (including capital) variable. |
|  |
|  |

|  |
| --- |
| Box 11.2 How are peak network costs currently recovered in charges? |
| Victorian and New South Wales distribution businesses recover between 40–66 per cent of their total revenues through non-peak usage charges, with smaller proportions recouped from peak period and fixed charges. For households, which rarely face any time-based prices, the reliance on non-peak usage charges is higher again. Capacity charges are mainly applied to large business users (box 11.1).  However, Ausgrid has recently sought to rebalance its tariffs, increasing the proportion of its revenue recovered through fixed charges and peak energy charges (Ausgrid 2012b). Also, while its forecast revenue from capacity charges is projected to be much the same as in the 2008‑09 to 2012‑13 regulatory control period, there has been rebalancing of these charges across the customer base. A program to replace household accumulation meters with standard interval meters has assisted Ausgrid to rebalance their tariffs.  Revenue recovered by tariff component for all customers  Per cent, by Victorian and New South Wales distribution network service providersa  a Ausgrid, Essential and Endeavour Energy, Ergon Energy and Energex are based on forecast 2012‑13 revenues, while Victorian distribution network service providers’ revenues are based on 2010 revenues. Capacity charges apply to parties — mainly large businesses — that place a sufficient volt-ampere (VA) loading on the network infrastructure (which may require particular substation capacities). |
| *Sources*: AER (2012n, pp. 124‑7); Ausgrid (2012b, p. 12); Ergon and Energex (pers. comm., 2013). |
|  |
|  |

The limited use of genuine cost-reflective pricing reflects several factors.

* Most importantly, most customers do not have interval or smart meters capable of recording energy use or power requirements by time.
* Retail prices are often regulated, which means that any pricing flexibility at the network level can only be imperfectly replicated at the retail level. That severely mutes any possible demand response, thereby forgoing the network savings that motivate cost-reflective pricing in the first place.
* Governments are likely to be more sensitive to losers than winners from pricing reform. There is also a (generally poorly informed) concern that time-based pricing adversely affects lower-income consumers. There is an associated view that where this is so, tariffs for all consumers should be re-structured to ameliorate this. While it is appropriate for governments to protect vulnerable consumers, this should be achieved through transparent and targeted measures — such as formal community service obligations or obligations written into the National Electricity Law and the Rules (a matter covered in greater detail in section 11.9). Businesses would then set tariffs, subject to the regime regulated by the Australian Energy Regulator (AER). However, state governments continue to set licence conditions and, therefore, have a pervasive influence on businesses’ activities. Some privately owned distributors claim to be influenced by unwritten ‘guidance’ from jurisdictional governments (which is backed by their potential to write conditions into licence agreements or to restrict other aspects of commercial activity, if businesses do not fall into line). The ‘moratorium’ on time-based network pricing in Victoria (which is to elapse in 2013) is one such example of the latter, with its implementation more akin to a ‘gentlemen’s agreement’ unsupported by any specific written direction.

## 11.3 Do the National Electricity Rules facilitate time-based and other efficient pricing approaches?

Principles and requirements for determining network prices are set out in Clause 6.18 of the Rules.[[4]](#footnote-4) The clause provides both the scope and encouragement for distribution businesses to adopt efficient pricing regimes. Moreover, in assessing the pricing proposals of distribution businesses, the AER can pursue changes to non-compliant proposals.

However, the pricing rules provide very little real guidance about prices. Among other aspects, the Rules specify that prices for a specific retail class of customers must lie *somewhere* between the avoidable and stand-alone costs of supplying them. The former represents the cost savings from not serving a particular tariff class, assuming network businesses continue to provide all other services. The latter represents the much higher cost from serving the customers concerned, with all other customer types not being supplied. The gap between the two is often described as the ‘subsidy-free zone’, because if prices are lower than the avoidable costs, the relevant customer class is being subsidised by others, while if prices are higher than the stand-alone costs then they are clearly paying too much (subsidising others).

Unsurprisingly, given the economies of scale and scope that characterise distribution, there can be a large divergence between these lower and upper cost bounds.[[5]](#footnote-5) This means that within an overall revenue or price cap, a wide mix of charging structures that potentially have little resemblance to efficient pricing will be compliant with the rules (table 11.1) — a point also emphasised by the AEMC (2012u, p. 184).

In fact, neither price bound is appropriate. Instead, long‑run marginal cost (LRMC) pricing (box 11.2) is widely regarded as the most efficient (as explained further in section 11.4). Though not silent on the value of LRMC pricing, the Rules give it more of a passing nod than a real endorsement — businesses ‘must take [the concept] into account’ in deciding tariffs or charging parameters (clause 6.18.5(a)). The legal convention is that ‘take into account’ is a weak condition, even when preceded by ‘must’. The AER echoed this view, claiming that:

… the requirement to ‘take into account LRMC’ is very broad and provides limited scope for enforcement … (AER 2012a, p. 17)

A further significant deficiency in the Rules is that the apparent ‘subsidy free zone’ between the stand-alone and avoidable costs is more apparent than real. This reflects the broad description of customer classes. Customer classes must share *some* common features, such as voltage levels, the amount of power used and the nature of the end use (domestic, business, commercial or industrial).[[6]](#footnote-6) There remains plenty of scope, given such general classes, for significant variations in the patterns of consumption of their constituent customers, and accordingly, in the costs of supplying them. In particular, the Rules do not constrain large cross subsidies between customers with peaky consumption patterns and those without.

Therefore, as discussed in section 11.7, the Commission considers that a tightening of Clause 6.18.5(b)(1) would help in facilitating time-based pricing for distribution networks (as well as to support some other efficiency enhancing pricing reform).

Table 11.1 Estimates of annual distribution network costs and charges

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| Business | Tariff classa | Stand-alone cost | Avoidable cost | Tariff revenue |
|  |  | $m | $m | $m |
| ETSA (2012‑13) | Major business | 75 | 4 | 12 |
|  | HV business | 84 | 3 | 36 |
|  | LV business | 386 | 71 | 330 |
|  | LV residential | 524 | 208 | 401 |
| ETSA (2010‑11) | Major business | 72 | 4 | 9 |
|  | HV business | 80 | 3 | 25 |
|  | LV business | 367 | 67 | 247 |
|  | LV residential | 499 | 198 | 303 |
| Ausgrid (2012‑13) | Sub-transmission | 202 | 4 | 6 |
|  | HV business | 558 | 6 | 49 |
|  | LV business and residential | 2 129 | 263 | 2 047 |
| Ausgrid (2010‑11) | Sub-transmission | 598 | 3 | 5 |
|  | HV business | 880 | 5 | 38 |
|  | LV business | 1 384 | 58 | 672 |
|  | LV residential | 1 405 | 178 | 745 |

aSub-transmission is 33 kV and above, HV is high voltage (nominally 5–22 kV), LV is low voltage.

*Sources*: Ausgrid (2010c, pp. 44; 2012b, p. 34); ETSA Utilities (2010a, pp. 59; 2012a, p. 66).

## 11.4 Designing time-based prices for distribution networks

### LRMC as the underlying basis for time-based distribution network charges

Many see network services as a single product — transporting power — when in fact, they are comprised of many different products, each with different long‑run costs. In particular, the long‑run costs of supplying power at peak use times are quite different from other times, because a substantial amount of additional investment is required to supply the former. In that sense, peak and off-peak network services can be seen as related, but different products. As for products throughout the economy, efficient pricing aims to achieve a reasonable alignment between prices paid by consumers and the costs of supply.

A wide body of economic literature and other opinion identifies LRMC pricing as the appropriate pricing methodology to achieve this efficiency goal.[[7]](#footnote-7) LRMC is the marginal network cost of supplying peak demand over a period that is sufficiently long to make all costs (including capital) variable. A business must charge at least LRMC to avoid a loss. (In contrast, short‑run marginal costs take existing capital as given, and prices based on SRMC will not allow a business to recover sufficient revenue to finance future required investment.)

There are many practical challenges in calculating LRMCs — brought into focus by the AEMC (2012u, pp. 184‑5); Marsden Jacob Associates (2004) and Turvey (2000b, p. 2). The appropriate method depends on many factors, including:

* the reasonableness of forecasts of future required capacity and technological change, recognising that LRMC is a forward looking cost measure
* the specification of the appropriate increment, recognising the lumpy nature of the relevant investments[[8]](#footnote-8)
* the appropriate time horizon over which to make the calculations
* the discount rate (the use of which is required because all measures of LRMC must discount future streams of costs and outputs into a single number)
* preferences about price stability. (Some measures of LRMC imply more volatile price paths than others.)

LRMCs must recognise the practical engineering and commercial realities of how network augmentations proceed. As Turvey (2000b, p. 46) notes ‘The forecast cannot be made without the collaboration of engineers’ — which is why harnessing the expertise of the networks is critical.

Not surprisingly, there are several methods for calculating LRMC — each with its own advantages and disadvantages (covered in detail by Marsden Jacob and Associates, 2004).[[9]](#footnote-9) This is a highly technical area — with the choice determined by data availability and the purpose of the cost measure, among other factors. The complexity is revealed by the diversity of approaches used in utility regulation in Australia and overseas.

However, it is possible to produce some meaningful estimates, and even proxies for LRMC are likely to provide a basis for prices that better signal the true costs of meeting peak demand than do the prices currently charged to most customers. The practical difficulties of estimating LRMC are not much different from other markets where time-based pricing applies.

Once computed, the LRMC could be incorporated in charges in several ways — including volumetric charges, access charges, charges linked to a customer’s maximum demand, and targeted charges based on particular demands placed on specified parts of the network (such as a localised substation, neighbourhood feeder, sub transmission line, transformer or even interconnector). The precise nature and combination of these is again a matter for distribution businesses (in consultation with affected parties).

However, if LRMC pricing is to play an effective role in managing and moderating peak load demand, then the tariff structure must have a significant time-based component. The Commission’s expectation is therefore that distribution network businesses’ pricing proposals to the regulator would involve significant and appropriate use of critical peak prices, and (especially for business customers) peak capacity charges.[[10]](#footnote-10)

LRMC pricing for peak demand by distribution businesses would have several major implications.

* Prices would be higher at peak times because of the greater long‑term costs of supplying at peak times.
* Consumers would only use power at critical peak times up to the point where they would be willing to pay for it — an important efficiency criterion.
* The latter in turn offers scope for major savings from deferring costly new investment to meet typically short‑lived peaks in demand.
* The overall electricity charges for consumers who tend to use less peak power would decrease, eliminating cross-subsidies, often to the benefit of lower-income consumers.

### Issues related to the geographic differentiation of LRMC

The costs of meeting peak load demand and of augmenting the distribution network vary considerably across different locations. Ideally, significant differences of this nature should be reflected in an efficient time-based pricing regime. As AEMC (2012e) observed in its Power of Choice Directions Paper:

DNSPs [Distribution Network Service Providers] have to ensure they provide sufficient capacity to meet demand in every part of their network, so differing demand patterns in different locations can have a substantial impact on costs. (p. 64)

Where the network costs of supplying consumers differ by location, the network tariff should likewise vary by location. (p. 206)

While the Commission has been unable to source comprehensive data on the nature and significance of localised network peaks, it has been told by distribution businesses that there is considerable variation. For example:

* in the outer suburbs of a large city, peaks may occur slightly earlier or later than in inner suburbs, largely reflecting differences in commuting distances
* in an area of the network with a high share of dairy farms, peaks tend to be early in the morning
* at a more aggregated regional level, peaks depend on the season. The latter observation is supported by AEMC data showing that peaks are typically in summer in South Australia, Victoria, Queensland and New South Wales, and over winter in Tasmania (chapter 9).

NSW DSNPs (sub. DR85, pp. 6‑7) claimed that temperature trends were changing by jurisdiction, which, if they continued, would also affect the future geographical pattern of peak demands. For instance, according to their submission, Queensland, and to a lesser extent New South Wales, has shown a trend towards more warm days, while this pattern has not occurred in Victoria.

Again, the precise way in which time-based prices should encompass significant geographical differences in costs related to peak demand is a matter for distribution businesses, the regulator and their customers, but should not be frustrated by the Rules.[[11]](#footnote-11) However, at a broad level, the Commission’s expectation is that any geographic component of a time-based charge for access to the distribution network would reflect significant differences in:

* the rate of growth in peak demand and the timing of network peaks within discrete locations of the network
* the location of end users relative to generation sources and, hence, their call on distribution poles and wires
* the location-specific costs of expanding the network.

The Commission recognises that significant geographic differentiation in time‑based charges could exacerbate equity concerns about the approach in the broad. However, most of these concerns could be addressed as part of the more general protection to be provided for vulnerable consumers (recommendation 11.8). It is not clear that support should go beyond vulnerable groups.

* Support has to be funded from either taxpayers or other consumers, many of whom may be poorer than the parties they end up subsidising.
* For many other goods (such as food and petrol), governments do not remove regional variations arising from the higher costs of serving some customers.
* Moreover, where governments do apply postage stamp pricing, the quality of service is usually not constant across regions. For example, in electricity, interruptions are more frequent in non-metropolitan areas. Once quality is taken into account, the effective price of services in many regional areas is higher than the notional price would suggest — suggesting that some degree of real price variations is already acceptable.
* Requirements for cross-subsidies from low‑ to high‑cost regions would undermine the motivation for network businesses and communities to seek alternative lower-cost solutions for transporting power (for example, distributed power).

However, in the event that governments wish to smooth regional cost-based price differences, they should do so to the least extent possible, with any such support transparent and delivered efficiently (see below).

### How good is the current information on LRMCs?

Accurately estimating LRMCs in the distribution sector is intrinsically challenging. As SP AusNet observed:

It is of course immensely difficult to accurately measure the long‑run marginal costs of consumption. These are in a state of constant flux, and are affected by both short and long‑run factors, they are reliant on accurate consumption forecasts, accurate costing of capital and labour costs, accurate knowledge of the timing of required capital investments costs and perfect information of future technological advances. (SP AusNet 2012, p. 46)

Moreover, network investments are not just related to peak load growth (or options to cost-effectively manage demand). The need to replace ageing assets and to address externally imposed reliability requirements, are but two examples of other investment drivers. Indeed, because of economies of scope, investments will often have more than one objective. In these circumstances,[[12]](#footnote-12) the LRMC related to the peak demand component would need to be apportioned.

In this environment and within a system that has not been oriented to time-based pricing, distribution businesses have tended to use compromised forms of LRMCs for setting charges, which usually straddle a mix of marginal and average cost concepts. Nevertheless, there are many published estimates of LRMCs for distribution networks that can be used as a starting point for pricing supply at critical peaks.[[13]](#footnote-13) Better information would help develop improved measures of relevant LRMCs. The increased use of smart sensors to collect load data at a fine detail across networks may assist, extending the data already available at the zone substation level (Leung 2012).

### Some related demand forecasting issues

Forecasts of peak demand are integral to the network planning and revenue determination process, and thereby to the timing and scale of network augmentations and the prices paid by consumers.

A phased introduction of time-based pricing by distribution businesses would increase the complexity of the AER’s task in this area, as would the way in which retailers choose to pass through such prices (Ergon Energy, sub. DR63, p. 7). Specifically, there would be a need for forward looking adjustments that take account of the potential reductions in demand from more cost-reflective prices at peak times, and the consequences for efficient levels of new investment and the revenues required to support them. As noted earlier, the Commission recommends a change in the Rules to achieve this (recommendation 11.5).

This added dimension to the revenue determination process could, if undertaken well, provide a potentially powerful spur for distribution businesses to implement efficient time‑based pricing. That is, a distribution business that did not implement time‑based pricing to the degree provided for in the determination could expect to experience a net revenue shortfall over the regulatory period. Fundamentally, this is because it would be obliged to build capacity — at high cost — for the increased peak demand arising from non-cost-reflective prices. Yet its regulated revenue allowance would not be enough to recover these costs because the AER would have based the allowance on lower demand forecasts and lower investment requirements.

Inevitably, distribution businesses and the AER will make errors in calculating the LRMC and in estimating the demand response to peak pricing. The issue is how to test whether pricing is moving in the right direction and to limit the scope of those errors and their consequences. In the medium term, a test of improvement would be evidence of a substantial widening of the gaps between off-peak and critical peak prices. If this did not eventuate, the incentive regime (and the Rules and guidelines that underpin them) would have to be re-visited. A prerequisite for any such improvement would be elimination of the other important obstacles to peak pricing — retail regulation and the absence of smart meters.

Given the greater role for LRMCs in determining peak prices and generating demand forecasts, it would be important for the AER to have a strong and growing capacity to assess the reasonableness of LRMC estimates and their implications for demand forecasts. (This provides another reason for additional resourcing of the regulator — chapter 21.) The iterative process of developing better estimates of the LRMC is a form of benchmarking in its own right — albeit one that targets allocative efficiency by establishing a LRMC price benchmark, rather than technical efficiency, which is the more usual focus of benchmarking exercises.

Trialling of new tariff structures, and carefully assessing their results, should be a key part of the process for progressively moving towards a robust time-based pricing regime (see below). In this respect, ongoing trials should assist in price setting and in the more precise estimation of demand elasticities. After the Victorian Government lifts the moratorium on time-based pricing, experiences in that state should also provide lessons to distribution network businesses in other jurisdictions. For example, Jemena, a Victorian distribution business, is transitioning to cost-reflective network tariffs in 2013 (sub. DR77, pp. 15‑16).

### Defining ‘peak’ demand

Time-based prices will only do their job well if the definition of the peaks that underpin those prices is a good reflection of the actual peakiness of demand — demand that drives investment in additional network capacity. There is general agreement that current ‘time-of-use’ tariffs generally apply the concept of ‘peak’ periods much too broadly and frequently to materially moderate critical peak network demand and the investment burden that comes with it.

However, there is no clear consensus on how peak demand, and more particularly critical peak demand, should be defined. The fact that the frequency, duration and significance of peaks varies by location adds further to the difficulty of defining peak demand. Also, the demand response of some customers to time-based pricing will moderate peaks, as these customers will economise on power or shift their consumption to non-peak periods. Hence, the definition of the peaks cannot be set solely on the basis of the current load profile.

Given these complexities, the Commission has not sought to specify how peak demand should be defined within a time-based pricing regime. Rather, distributors should determine this, in consultation with the other relevant stakeholders as part of the implementation process. However, the Commission reiterates that peak period charges that drive augmentation investment should be much more targeted to actual demand peaks than at present. Some other key considerations for any definitions include:

* the capacity to translate definitions into simple and understandable time-based tariff structures that facilitate the desired demand management approach
* the need to consider the costs and confusion that inevitably accompany changes in definitions.

The implication of the latter is that there should be a tradeoff between, on the one hand, the benefits of continually finessing tariffs and, on the other, the transactions costs for retailers and consumers associated with constant change and complexity. This suggests some gradualism in adapting tariffs over time. It also indicates the importance of engagement between network businesses, retailers, customer representatives and the AER on the means of iterating to a robust time-based charging regime.

## 11.5 A supervising role for SCER is a first step in implementing time-based pricing

Given the complexities of the task, the many other required changes in the system, and the likely aversion of some stakeholders to moving to time-based pricing, there is a risk that reforms will be either insufficiently coordinated or could stall. It is more likely that reform will occur if it is coordinated by a single body, which would establish realistic reform milestones and timelines, oversight progress against those timelines and, if required, bring stakeholders together to resolve specific roadblocks or unduly slow progress.

In principle, the Standing Council on Energy and Resources (SCER) would be the most appropriate body. It has responsibility for pursuing priority issues of national significance in the energy and resources sectors. Among its functions are to facilitate national oversight and coordination of governance, policy development and program management in these sectors; provide national leadership on key strategic issues; and enhance national consistency between regulatory frameworks — all of which would fit well with a responsibility for driving the implementation of time-based network pricing.

However, there is a complementary need for SCER to ensure that reform occurs in a timely way to maximise the benefits to consumers of efficient pricing (chapter 21).

Recommendation 11.1

***The Standing Council on Energy and Resources should oversee the progressive implementation of cost-reflective, time-based pricing for distribution network services, predicated on the long-run marginal costs of meeting peak demand. Amongst other things, the Council should:***

* ***following consultation with key stakeholders, set timelines for the various steps in the development and implementation process, having regard to:***
* ***the Commission’s proposed process (recommendations 11.2 to 11.9)***
* ***progress in making necessary changes elsewhere in the system***
* ***monitor compliance with those timelines***
* ***address any areas where greater engagement between key stakeholders (distribution businesses, retailers, state and territory governments, the Australian Energy Regulator and customer representatives) would assist the expeditious implementation of the new pricing regime***
* ***if and as necessary, take specific steps to address implementation delays.***

## 11.6 A NEM-wide licensing regime for network providers

One step that could be taken reasonably quickly to facilitate the implementation of time-based pricing for distribution networks would be to establish a single set of licence requirements for all network providers operating in the NEM. These should replace the current state and territory provisions, with the new requirements incorporated in the Rules. Such a licensing regime would reduce the risk that the pursuit of objectives other than the National Electricity Objective by state and territory governments could frustrate the introduction of cost-reflective, time-based network pricing. A shift in responsibility for enforcing compliance with licence conditions to the AER would be no less important than a move to common requirements — particularly in jurisdictions where governments also own the network providers.

In making these observations, the Commission is not questioning the right of jurisdictions to pursue equity and other non-efficiency related objectives linked to the provision of electricity services. However, in the past, this has sometimes occurred in ways that have been inimical to the longer‑term interests of consumers overall and the wider community. One example is the implementation of reliability standards, where the benefits for consumers (as reflected in their willingness to pay), relative to the costs involved in upgrading networks, are seemingly ignored (chapter 14). And of more direct relevance to time-based pricing are instances of jurisdictional governments intervening implicitly or explicitly to modify charging regimes for equity reasons, such as:

* the Victorian Government’s moratorium on time-based charging
* South Australian legislation setting out derogations from the Rules for the 2010 distribution determination, and requiring that fixed supply charges not increase by more than $10 per year
* the Queensland Government’s direction in 2011 to its state-owned distribution businesses (Energex and Ergon Energy) not to recover from consumers $100 million of additional revenue that was approved following a merits review by the Australian Competition Tribunal. The Government, as the owner of the two companies, indicated that it would accept a lower rate of return on its equity.

Such instances are in conflict with the principle endorsed by all Australian governments that support for low-income or disadvantaged consumers should be provided through targeted and transparent instruments.

A single licensing regime would also have wider benefits — including for the transmission component of the NEM and by assisting the introduction of:

* a NEM-wide reliability framework (chapters 15 and 16)
* a common and efficient approach across jurisdictions to the provision of assistance to vulnerable consumers (see below).

Since the new licence requirements would replace existing jurisdictional licensing arrangements, they would not result in duplication and higher administrative burdens, and could encompass any relevant properly justified factors that vary between jurisdictions (concerns expressed by the ENA, sub. DR71, attachment 1, p. 9, trans. p. 330). Jemena (sub. DR77, p. 9) expressed the view that licence conditions should be somewhat like a driver’s licence, being:

… a minimal document simply certifying that the holder is a fit and proper person to engage in the licensed activity. All the conditions that attach to a licence should be contained in applicable law and other enforceable instruments external to the licence. The licence itself should not be a vehicle for promulgating policy.

However, current licences *already* act as vehicles for policy — albeit without much transparency or accountability. In that context, the Commission’s expectation is that a robust and transparent process (similar to that of a Regulatory Impact Statement) would inform the development process to minimise the possibility of gravitation to the most stringent (and costly) jurisdictional provisions in each area. This process would also help ensure that the subsequent licence conditions delivered net benefits to the community.

The Commission considers that the development of aspects of these new requirements might sensibly be tasked to the AEMC, which could undertake a framework review to assist the process of developing national conditions. The views of state and territory governments would be central to that review. It is also important that jurisdiction-specific licence conditions are only included where the framework review (which would effectively act as a Regulatory Impact Statement) could demonstrate that the benefits exceed the costs.

The AER would be responsible for enforcement of most new licence conditions and, where necessary, would seek advice on technical issues from the Australian Energy Market Operator (AEMO) or state-level regulators. However, for national licence conditions relating to safety, it would be appropriate for independent national or jurisdictional safety regulators (but not state or territory governments) to ensure compliance, rather than the AER. Nevertheless, as an economic regulator, the AER would still oversee incentive arrangements in technical areas, such as the Service Target Performance Incentive Scheme (and if nationally adopted, the F-Factor scheme).

The Commission has not sought to identify all the particular matters that the new licensing regime should encompass. However, reliability, the provision of assistance to disadvantaged customers or requirements to provide non-commercial services, and technical standards and safety requirements would be some of the matters to be included.

Below, the Commission has made some specific proposals relating to those consumers requiring support to meet higher bills following the introduction of time‑based pricing. These proposals address widespread concerns among participants about protection for vulnerable or disadvantaged consumers (Paul Brand, sub. DR53; National Seniors Association, sub. DR62; Origin, sub. DR64; MEA, sub. DR74; NAGA, sub. DR88). Suffice to say at this point, the criteria governing that support — or support provided through the provision of non‑commercial services — should be explicit in the new licensing requirements. Additionally, the requirements should specify how such community service obligations are to be financed (see below).

The Commission notes that preparatory work would have to occur to develop national criteria that identify customers in need of support and provide a uniform approach to funding that assistance. This should not delay the development of national licence conditions. As such, until uniform criteria and sources of funding are developed, each state and territory government would continue to be responsible for targeted financial support to address the affordability of electricity.

Recommendation 11.2

The Standing Council on Energy and Resources should initiate a process to establish uniform licence conditions for all transmission and distribution network businesses in the National Electricity Market.

* The uniform licence conditions should have regard to the Commission’s proposed changes to the reliability framework (recommendations 15.1 and 16.1) and should not conflict with, or impede, the implementation of that framework.
* The uniform licence conditions should be included in the National Electricity Rules and replace the current state and territory licence conditions.
* Standardised provisions governing technical standards and safety should ultimately be encompassed in the national licence conditions, but with a transition to recognise the practical implementation difficulties of any rapid changes in this area.

The Council should task the Australian Energy Market Commission to undertake a framework review to assist the transition to uniform licence conditions.

* The supporting framework review should clearly spell out the justification for any jurisdiction-specific conditions included in the new licensing regime.

Recommendation 11.3

Before incorporation into national licence conditions, preparatory work should be undertaken to develop a common approach to the identification of customers in need of special support to meet their electricity bills (recommendation 11.8).

Pending agreement on appropriate national criteria and approaches to funding, each state and territory government should continue to be responsible for targeted financial support to address affordability.

Recommendation 11.4

The Australian Energy Regulator should be responsible for ensuring compliance with most new licence conditions, with the exception that a relevant independent national, state or territory regulator should have responsibility for compliance with national safety licence conditions.

* The Australian Energy Regulator would still oversee any economic incentive schemes relating to safety and would need to ensure that revenue determinations took into account the agreed national safety standards.

The Australian Energy Regulator should be given authority under the National Electricity Rules and the National Electricity Law to:

* issue and revoke licences
* seek advice from relevant agencies on any technical matters relating to compliance assessment.

## 11.7 Tightening and augmenting aspects of the Rules

As discussed earlier, the Rules are vague about the use of LRMC for price setting. The Rules permit such pricing, but do not require it. The key clause in this regard is 6.18.5(b)(1), which requires only that LRMC be ‘taken into account’ when determining tariffs. The clause has had little impact — as shown by actual network pricing structures (box 11.2). Accordingly, an important precursor to pricing reform is greater discipline in the Rules about the application of LRMC principles.

ActewAGL (sub. DR59, p. 5) argued against any change, claiming the framework of the Rules allow it the flexibility to develop appropriate TOU pricing. Similarly, CitiPower et al. claimed that the current Rules do not present an obstacle to network tariff reform and that Rule changes — to strengthen the requirement for distribution businesses to propose tariffs that reflect LRMC — are not necessary (sub. DR90, p. 19).

However, commenting on the current Rules, SCER has noted that the way in which:

… the regulatory regime administered by the AER incentivises distributors to implement [efficient time-based] tariffs is unclear. Absent particular incentives to do so, there is no particular reason to expect that they will set tariffs in such a way to maximise the impact on peak demand, although nothing prevents them from doing so. (SCER 2011a, p. 12)

The AEMC’s assessment is equally critical:

… while LRMC is a fundamental concept for efficient pricing, it is reflected as a relatively weak obligation in the rules. (AEMC 2012u, p. 185)

While this vagueness in the Rules persists, it is unlikely that the AER could require adherence to genuine LRMC methodologies, putting at risk the transition to cost‑reflective, time-based, pricing — or at the very least detracting from the quality of the pricing regimes that emerge.

The timing of a rule change to address this problem would depend on progress in implementing the other preconditions for time-based pricing. This timing might reasonably be the subject of discussions between stakeholders and SCER as part of the latter’s proposed oversight responsibility (recommendation 11.1). But it is an important change to be made at some point. In essence, clause 6.18.5(b)(1) should require that time-based pricing be predicated on LRMC, with the task of the AER being to determine whether pricing proposals are reasonable from this perspective, while recognising the practical computational challenges.

At some point in the transition process, the rules governing the setting of tariff classes (clause 6.18.3(d)(1)) should also be tightened. Currently, this clause refers to the need to group customers on an economically efficient basis, but again on a ‘have regard to’ rather than a ‘must’ basis. Also, it does not explicitly refer to the geographic dimension of efficiency in regard to setting tariff classes — an omission which has the potential to impede variations in time-based prices across regions to reflect significant differences in the cost of meeting peak demand. The Commission is therefore proposing an amendment to remedy these shortcomings. The AEMC has proposed a similar improvement to the distribution pricing principles via a rule change (AEMC 2012u, pp. 185‑6). Such changes would not give distribution businesses carte blanche to gouge consumers. Under the Commission’s proposals, all distribution network businesses would be subject to an overall revenue cap (chapter 12).

Finally, the Rules will also have to be amended to give the AER the power, when assessing pricing proposals, to consider whether a business’s forward peak demand forecasts make reasonable provision for the effects of time-based pricing in constraining demand. Otherwise, regulatory revenue caps will be higher than necessary, providing windfall gains to distribution businesses. To discharge this responsibility successfully, the AER will need to develop its demand forecasting capacities.[[14]](#footnote-14)

Recommendation 11.5

When the process of implementing cost-reflective, time-based prices for distribution network services is sufficiently advanced, the National Electricity Rules should be amended to:

* ensure that any time-based tariff is determined by (rather than ‘take into account’) a reasonable estimate of the long-run marginal cost for the service concerned
* ensure that the grouping of customers for the purposes of setting time-based tariffs is based on economic efficiency (rather than ‘having regard to’ it)
* make it explicit that significant differences in the long-run marginal cost of meeting peak demand between locations and across customer groups should be reflected in network pricing structures
* ***with any deviation from this principle arising from any state or territory government decisions about community service obligations transparently funded by the relevant jurisdiction.***

Recommendation 11.6

When the process of implementing cost-reflective, time-based prices for distribution network services is sufficiently advanced, the requirements governing assessments by the Australian Energy Regulator of pricing proposals by distribution businesses should be amended such that the regulator:

* can only approve a distribution business’s peak demand forecasts if they include reasonable estimates of the likely demand response to critical peak time-based pricing
* subject to the above condition, must approve any reasonable estimate by a distribution business of the long-run marginal costs of meeting peak demand.

To support these changes, the Australian Energy Regulator should develop a capacity to model demand responsiveness to time-based pricing.

## 11.8 Guidelines to support methodological development and data collection

The Commission also sees a potentially significant benefit in the AER developing guidelines on key methodological and definitional issues to underpin the operation of the new regime. The area in which guidelines would be most helpful would be the methodology for computing the LRMC of meeting peak demand. Such guidelines should specify factors to be included in the estimation of LRMC and an approved methodology or methodologies for that estimation. The guidelines should be developed in consultation with network businesses and should not be overly prescriptive. The AER should remain open to the use of different approaches, depending on the particular circumstances of a network business. Indeed, the Commission’s expectation is that the guidelines would require iteration as experience with time-based pricing, and calculating the costs of peak demand, increased. The Commission further notes that a change in the current Rules would be required to enable the AER to publish guidelines of this nature.

The AER should also have the scope to publish binding guidelines about efficient tariff structures,[[15]](#footnote-15) the definition of network ‘peaks’ and associated critical peak pricing events. Establishing sound approaches in these areas at an early stage of the implementation process is likely to be very useful in buttressing the bona fides of time-based pricing, and will ensure that those using power at peak times pay a genuinely cost-reflective price. This would then see some customers reducing their demand at these times and, accordingly, lower network infrastructure needs. Again, however, it is important that any such guidelines be developed in consultation with relevant stakeholders, not be overly prescriptive and formulaic, and provide scope for iteration over time.

Recommendation 11.7

The National Electricity Rules should be amended to:

* require the Australian Energy Regulator to publish guidelines on the appropriate methods for estimating the long‑run marginal costs of meeting peak demand, and the factors that should be encompassed in those estimates
* give the Australian Energy Regulator the authority to publish guidelines about efficient, time-based tariff structures, including definitions of ‘peak’ pricing events.

These guidelines should be developed in consultation with the relevant stakeholders and should be improved over time as the implementation of time‑based pricing progresses.

The Commission notes that the AEMC has made a final rule determination that will require distribution businesses to publish an annual planning report covering the subsequent five years, with information provided at the sub-transmission, feeder and zone substation level (AEMC 2012c, p. i). This should help to overcome some of the current gaps in the data relevant to estimating locational differences in the cost of meeting peak demand. Such information would assist networks in incorporating a geographical dimension in future time-based prices.

## 11.9 Addressing affordability and equity issues

Perceptions about the effects of time-based charging on equity have been an obstacle to the use of time-based pricing in Australia and overseas.

### The distributional effects of time-based pricing

Cost-reflective, time-based pricing may see distribution businesses recoup a significant proportion of their total revenue from those drawing on the system during peak demand periods. Other things being equal, they will then be less reliant on revenues from fixed charges and usage tariffs during non-peak periods. If this rebalancing is appropriately translated into retail electricity prices, those who:

* continue to use large amounts of power at peak times will face considerably higher bills
* were already low users at peak times, or those willing and able to respond to the price incentive to economise on peak period consumption, will experience lower bills — or at least lesser increases.

As noted earlier, low-income households tend to be relatively low users of peak load power. Hence, as a group, they should benefit from the removal of the current cross-subsidies from those who put relatively small demands on the network at peak times to those whose demands are larger in those times. In its recent submission to the Senate Select Committee Inquiry into Electricity Prices, the South Australian Council of Social Service (2012, p. 16) noted that:

* low-income households have less peaky demand because their houses are usually relatively small, air conditioning penetration is lower, and where air conditioners are fitted, they tend to be smaller
* as a result of this less peaky demand, the introduction of cost-reflective retail and network pricing would see average bills for these households fall by 10 to 20 per cent — implying ‘that it is a reform worth pursuing.’

Even so, inevitably *some* low-income households, or otherwise vulnerable consumers, would be disadvantaged by the introduction of time-based pricing (and by the associated recoupment of the costs of smart meter installation).

### The efficient pursuit of equity objectives

Equity as well as efficiency matters for community wellbeing. Hence, the Commission recognises that, in pursuit of equity objectives, governments may reasonably seek to intervene to improve the affordability of electricity services for some consumers — including the cost of distribution network charges they incur. However, not all forms of intervention are equally efficient. Using the most efficient means to address genuine equity or hardship issues will minimise the costs imposed on those not in receipt of support, and deliver a better outcome for the community as a whole.

The key here is to use measures that explicitly target vulnerable (or otherwise unreasonably disadvantaged) consumers. Indeed, as the Commission discussed in its recent report on urban water, utility services are already subject to targeted mechanisms for assisting vulnerable consumers (box 11.3). In contrast to cross-subsidised usage charges, such targeted instruments do not lead to inefficient demand responses by consumers who do not require support. And, if well designed, targeted support might have relatively little impact on the demand responses of recipients.

As well as concessions and rebates, an appropriate suite of instruments for helping vulnerable consumers to accommodate time-based pricing might include targeted subsidies for air conditioners compatible with direct load control, or for improving the thermal efficiency of their dwellings (chapter 10). These could be funded from general government revenue or by a small publicly-divulged increase in the fixed access charge. More broadly, there may be a case for some shift away from service-specific support to assistance via the Australian Government tax and transfer system (see below).

Some other options that have been suggested would be inappropriate. For example, common prices across regions with very different costs of service would poorly target the people who justifiably need assistance. Similarly, a universal exemption from time-based pricing for low-income groups would be a blunt instrument. For example, it would include people who could shift their demand readily were they to face higher prices. The greater the carve outs from cost-reflective pricing, the lower are the network savings and the higher are average network charges for non-peak use and the associated hidden cross-subsidies.

|  |
| --- |
| Box 11.3 Utility concessions and rebates |
| In addition to welfare measures provided by the Australian Government (and funding for concessions under the National Partnerships Agreement for utility concessions to pension cardholders), state and territory governments provide a variety of concessions and rebates to households for their electricity and other utility services. Although administered by state and territory governments, eligibility for the latter tends to be linked to Commonwealth concession cards, with over five million cardholders (including 3.6 million Pensioner Concession Cardholders).  Energy concessions and rebates are generally worth $200–$400 a year to the recipient, although in Victoria the amount of assistance is determined as a percentage of the electricity bill (AEMC 2012w, p. 23). Emergency payments may also be available through community welfare organisations. Such forms of assistance can be provided directly to a consumer as a rebate, or indirectly through their retailer as a discount on their electricity bill. As well as differences in value and form, eligibility requirements also vary across jurisdictions.  In its report on the urban water sector, the Commission (PC 2011c) analysed the role of concessions and rebates in addressing affordability issues for vulnerable consumers. It concluded that, compared with delivery through cross-subsidised usage charges, these forms of assistance can better target those in genuine need and involve smaller costs to efficiency. |
|  |
|  |

### Current arrangements for delivering support must be improved

Given the potential for poorly configured support for vulnerable (or otherwise unreasonably disadvantaged) consumers to undermine the effectiveness of time‑based pricing, the Commission considers that robust criteria for such support should be developed — and incorporated in the new NEM-wide licence conditions for network providers (recommendation 11.2).

Ideally, eligibility criteria would principally target support at households who have both low income (or are otherwise financially vulnerable) *and* face inherently high supply costs. In practice, neither existing concessions nor currently operational definitions of ‘vulnerable’ closely accord with these requirements.

More generally, as noted by Australia’s Future Tax System Review Panel (2009) and in the Commission’s urban water inquiry (2011c), current concessions:

* are utility specific, with a confusing array of assistance collectively available for essential services
* employ a range of approaches of varying effectiveness and administrative efficiency, and with differing impacts on economic efficiency and equity in the broad
* tend to treat holders of Pensioner Concession Cards (including aged pensioners) more favourably, despite some pensioners receiving higher incomes than other vulnerable groups.

But while the case to improve the delivery of financial assistance to households facing long‑term difficulty in affording utility services appears a strong one, the best way forward is less clear — with the choice in practice being between imperfect alternatives.

Accordingly (and consistent with the Commission’s recommendation in its urban water inquiry), the Council of Australian Governments should, as soon as practicable, commission a review of all forms of assistance for utility services provided across all levels of government. That should include an assessment of whether the Australian Government’s tax and transfer system could deliver aspects of that support more equitably and efficiently. Based on the outcomes of this review, criteria for assistance for vulnerable consumers, and the means of funding that assistance, should then be written into the NEM-wide network licence conditions (and may also require an obligation, under the National Energy Consumer Framework, for retailers to pass these on as tariff reductions).

Recommendation 11.8

The implementation of cost-reflective, time-based pricing for distribution network services should be accompanied by assistance for vulnerable consumers, which should target those who:

* are potentially exposed to large price increases and who do not have reasonable opportunities to switch their demand to non-peak periods
* will potentially face significant difficulty in meeting the fixed component of network charges.

The Standing Council on Energy and Resources should develop common criteria for identifying who should receive such assistance and how it should best be delivered. These criteria should be based on the outcomes of a review commissioned by the Council of Australian Governments of concessions for utility services across all levels of government (consistent with recommendation 8.1 of the Productivity Commission’s Urban Water Sector report).

These criteria, and a commitment to transparent funding of the electricity sector‑specific support, should then be reflected in the new National Electricity Market‑wide licence conditions for network businesses (recommendation 11.2).

## 11.10 The nature of the transition to time-based pricing

The widespread use of targeted time-based pricing for distribution network services is a big change from past practice. While many customers will be winners, there will be some losers. There will be adjustment costs for network businesses, retailers, their customers and the AER. In addition, some important complementary initiatives are required. Accordingly, a carefully planned transition is essential, which involves appropriate engagement between the various stakeholders (section 11.11), and should take into account the costs of change. As outlined above, the Commission is proposing that this transition process be oversighted and driven by SCER (recommendation 11.1).

A relatively easy first step would be to extend cost‑reflective, time-based, pricing of the network to all major industrial and commercial customers (box 11.4). Large industrial customers in Australia have had half-hourly interval metering for many years. Many are already routinely being sold electricity based on tariffs and contracts with pricing that varies by time of use (Etrog Consulting 2012. p. 7). Accordingly, time-based pricing in this commercial area is well tested. The Major Energy Users expressed concern that broadening the application of cost-reflective prices to all large users has the potential to create significant and unnecessary price pressures on them (sub. DR66, p. 16). However, this argument is not convincing. Such users would be charged prices that reflected the costs of the services they receive at given times (bringing network pricing into line with the treatment of some other input costs, such as wages). If there are large consequent price pressures (in aggregate) for some users in this group, it presumably reflects the net current (inefficient) subsidies to them. Moreover, price reform must commence with some parties.

However, there would be a longer transition to fully-fledged time-based pricing for smaller businesses and households. This reflects the need for effective engagement by distributors and retailers with customers and a range of complementary reforms, including the:

* removal of retail price regulation (recommendations 12.2 and 12.3). Under arrangements in some jurisdictions, there is currently little scope for cost-reflective network charges to be passed onto customers — obviating the purpose of efficient network pricing. Moreover, retailers with a greater share of peakier customers would be forced to absorb the extra costs of such users. The Energy Retailers Association of Australia stressed that in any transition to TOU prices it is essential that retailers not be obliged to absorb costs arising from network tariffs that they cannot pass through to consumers (sub. DR76, p. 5)
* gradual rollout of smart meters targeted at areas where network capacity limitations are greatest (chapter 10). This suggests that cost-reflective pricing for households and businesses would initially only occur in some regions. It should not be problematic to have households in one area on flat tariffs and others in another area on time-based charges, as this already occurs in trials of time-based charges. Nevertheless, ultimately all customers would face time-based charges.

|  |
| --- |
| Box 11.4 Time-based network pricing regimes for industrial and commercial customers |
| Current time-based pricing regimes for larger industrial and commercial customers provide one indication of the sorts of tariff structures that might emerge where time‑based pricing is extended to other customers, including households.  SP AusNet’s critical peak network tariffs for businesses apply from 2 pm to 6 pm on five nominated days across the December to March period. Its charges are uniform across the network. SP AusNet uses weather forecasts to signal the likelihood of a nominated critical peak day up to a week in advance, and will confirm by 2.00 pm (AESDT) of the preceding day that critical peak event tariffs will apply.  As an example, its Critical Peak Demand Multirate tariff for one set of large customers comprises an off-peak charge of 3.252 cents per kWh and a standard peak charge of 5.934 cents per kWh (SP AusNet 2013b). However, during the nominated critical peak events, customers are charged a critical peak price of $58.694 per kVA per annum, where the kVA amount is calculated as the average of the maximum kVA recorded on the five nominated days. For the sake of illustration, were the relevant average to be 200 kVA over the five days, then the customer would be charged around $12 000 for their load demand on the system during the relevant 20 hours. For the sake of simplicity, supposing that the business recorded 200 kVA of load demand *throughout* the entire 20 hour period and that the power factor was unity (that is, the need for correction could be ignored), then the implicit cost per kWh during the 20 critical peak hours would be around $2.95, or nearly 100 times the off‑peak price. (The differential would be higher than this if the above assumptions were relaxed.)  These schedules highlight that genuine time-based network pricing can involve some steep, but short‑lived price spikes (balanced by offsetting lower prices during other periods), but it is possible to inform customers about when these will occur so they can respond accordingly. However, caution is required in extrapolating likely time-based tariff structures for households from arrangements for larger industrial and commercial customers. An important consideration is the different demand traits of household customers — particularly their peak use patterns. The important point is that it would be distribution businesses in consultation with the regulator, retailers and customers that would be best placed to determine what pricing structures would be most appropriate. |
|  |
|  |

Retailers and distributors must also devise arrangements to provide consumers with advance warning that critical peak prices are to be applied and, thereby, with the opportunity to adjust their power consumption. In some cases, people might request that the distribution business or retailer control their key power-using appliances — mainly air conditioning — during these peak hours (‘direct load control’, as discussed in chapter 10).

Another key component of the transition process will be to determine an appropriate path to move from current pricing structures for households and small businesses to the sort of pricing endpoint that targets the 40 to 80 hours of critical peak demand a year. While the Commission has not sought to prescribe particular price paths, it observes that wider use of TOU network tariffs embodying relatively broad peak (and shoulder) components might be beneficial as an initial step. While Ausgrid’s experiences in New South Wales indicate that such charges do not achieve significant network efficiencies or offer much prospect of lowering consumer bills overall, they could nonetheless help to:

* increase consumer acceptance of time-based pricing. A survey of EnergyAustralia customers on TOU tariffs found that 71 per cent believed it was a fairer pricing system (this reflects that untargeted TOU tariffs still reduce cross-subsidisation between consumers, even if not significantly changing consumption habits)
* provide some useful information and data on the demand responsiveness of customers to time-based differences in prices.

However, these sorts of pricing regimes are unlikely to be effective in ensuring that future investment in the network to meet critical peaks is at a level that is supported by consumers’ willingness to pay. Accordingly, they would need to be supplemented by genuinely cost-reflective prices after an interim period. (In a cost–benefit analysis of options to reduce peak demand costs, Deloitte (2012, p. 60) found that untargeted TOU prices had the lowest benefits of any measure — and only one sixth of the benefits of critical peak pricing.) Moreover, an extended period of use would see expensive smart meter technology effectively underutilised. Indeed, the Commission’s modelling suggests that if the transition to more cost-reflective forms of pricing is too slow, the case for rolling out smart meters in the medium term becomes commensurately more problematic. Nevertheless, TOU pricing may still be a useful long‑run complement to critical peak pricing, if for no other reason that it may habituate people to electricity consumption patterns that lower peak use overall. For example, it may promote the use of time switches and direct load control. This may make it easier for people to adjust their behaviour, if they wish to do so, when critical peak pricing is introduced.

A further fundamental issue is the degree to which consumers could choose not to face cost-reflective prices.

In Victoria, where the rollout of advanced metering infrastructure is well advanced, the Department of Primary Industries noted that the transition to flexible network tariffs will be on a voluntary basis for residential customers. This will include a ‘safe try’ period until March 2015, during which households will be able to switch back to their previous tariff without penalty if they are uncomfortable with the change (sub. DR94, p. 9).

Any capacity to revert to the *original non-time-based* retail tariff would significantly reduce the sort of response that such critical peak prices are intended to induce. Under a voluntary ‘safe try’ model, many of the peakiest users (the recipients of cross-subsidies and the source of costly network usage) would likely opt to retain the hidden subsidies they receive, largely eliminating the scope for cost savings for those electing to shift to time-based charges. This situation is shown in the left hand chart in figure 11.1. The motivation for moving to time-based charging would therefore be relatively weak.

An alternative approach would be to give consumers several options. They could:

* stay with their current retail tariff structure, which would typically consist of a fixed charge and a usage price not related to the time of energy use. It is important to emphasise that it would be the non-time-based price *structure*, not the price *level* that would be preserved. Even though customers who so elected would not face a retail price that openly reflected the time variant network component, the distribution network business’s charges to retailers would still be time-based and would take into account critical peaks. Accordingly, retailers would have to raise the usage charges to householders on non-time-based tariffs to cover the higher costs that they would face during critical peak events
* shift to a time-based tariff determined by retailers (chapter 12), which would contain several pricing choices. For example, it might include TOU charges for winter and summer (with relatively shallow price differentials) accompanied by steep critical peak prices for the few hours a year where the network was under stress.

The AEMC refers to this approach as an ‘opt in’ model in that people would actively choose the type of retail tariff structure, depending on their consumption patterns, preferences and retailers’ offers (AEMC 2012u, pp. 172‑3).[[16]](#footnote-16)

While it might appear superficially similar to the Victorian Government’s approach up to 2015, the AEMC’s proposal would not sustain large cross-subsidies. The term ‘opt-in’ only relates to the *form* of the retail tariff, not to a capacity to avoid cost-reflective network charges. Over time, the AEMC’s proposal would erode the prospects for cross-subsidies. The dynamic would be as follows:

* the distribution network business would charge cost-reflective network charges (with critical peaks) to retailers, in accordance with the pricing principles identified earlier
* retailers would offer a variety of tariff structures, including (a) a standard fixed charge with an energy use charge but no critical peak prices and (b) more complex pricing structures that might include TOU and critical peak prices
* non-peaky users (and those peaky users who would be willing to change their consumption patterns) would logically prefer (b) and so over time would be likely to opt-in to time-based charges. As cross-subsidies were eroded, they would pay less than before. Moreover, likely falling peak demands would produce network savings, further reducing prices
* peaky users on tariff structure (a) would lose some of their cross subsidies, and so their non-time-based network usage charge would rise. This would likely encourage more customers in this tariff category to shift to (b), prompting further increases in usage charges for (a). This iterative process would continue until there was some equilibrium (shown as the right hand chart in figure 11.1). For example, some people might prefer the certainty and simplicity of flat tariffs, even if they were relatively high.

This is a stylised description of the dynamic process that could be expected. For example, in reality, there would be more than one time‑based retail tariff structure, as is the case in those trials where distribution businesses have implemented time‑based charging. This pricing approach would provide a natural progression to time‑based retail tariffs, giving time for retailers and consumers to learn, adapt and plan. However, if the progression were too slow, then it would lower the value of rollouts of smart meters. Without smart meters, there would be no prospect for time‑based tariffs — a chicken and egg problem. As discussed further in chapter 12, a more prescriptive approach might be required if retail tariffs did not adequately reflect time‑based network prices.

Ultimately, the Commission’s expectation, based on time‑based pricing regimes for industrial and commercial users (box 11.4), is that household network prices would be low for most hours of the day and most days of the year, but would ramp up considerably for relatively short, critical peak demand events (such as a heatwave) that impose large costs on the system. Peak periods could also be defined more routinely (such as higher-use periods of the day in winter and summer), but, if so, the peak price would be considerably less than that at critical peaks.

Figure 11.1 If people can escape the cost implications of cost-reflective prices, it undermines the goal of pricing reforma

|  |
| --- |
| Figure 11.1 If people can escape the cost implications of cost-reflective prices, it undermines the goal of pricing reform. This figures comprises of two charts, which compares the average usage charge over time between a no disadvantage model and a tariff class model. |

a In the left hand chart, the gap between PN and PC is for illustrative purposes. The actual gap would be negligible. This is because the scope for network savings relies on demand response at peak times by those consumers not staying with their existing tariffs (the ‘movers’). Those savings are likely to be small because movers would be generally less peaky. Moreover, any reduction in off-peak prices for movers will cut overall revenue for the distribution business. This reflects the fact that the typical household demand elasticities for electricity are modest, and that the inflexible prices for the non-movers would not give the network business any opportunity to recover revenue from higher peak charges for this group. Therefore, the network business must balance the loss of revenue from movers against slightly reduced costs — achieving a balance that would not reduce their return on assets. The equilibrium outcome would be a slight differential in average usage charges.

## 11.11 The importance of effective engagement and customer education

Participants generally agreed that whatever the particular transition path adopted, it is critical that there is appropriate consultation and information exchange between the various stakeholders. As noted by Sergici and Faruqui (2011, p. 19), ‘… changing a century-old ratemaking practice will require significant customer education and management of expectations’. They also observe that ex ante, many consumers say that they do not want pricing reform, but that after they have experienced such pricing, the vast majority report high satisfaction and want it to continue (p. 13).

One of the tasks of SCER in its role of overseeing the implementation process (recommendation 11.1) would be to ensure that, in a broad sense, there has been adequate engagement between the parties. A further focus, and one that is already an objective within SCER’s *Demand Side Participation Work Plan,* would be to ensure customers can easily assess the costs and benefits of electricity consumption decisions and access information about options to change their consumption. Within this framework, SCER could add forward priorities to the objectives of ‘informing choice’ and ‘enabling demand response’. Consequent actions and decisions should be informed by evidence from robust pricing and technology trials, and based on a cost–benefit framework.

However, in the Commission’s view, there would be benefits from imposing a formal requirement on distribution network businesses to engage with retailers very early in the development phase of revising network price structures. In this regard, the Commission is in accord with the Sustainable Regional Australia (sub. DR72, p. 2), which argued for absolute clarity in assigning responsibility for education of consumers ahead of pricing reform.

Imposing a formal requirement on distribution network businesses would help to:

* reduce the possibility that the costs of meeting peak network demand continued to be hidden (or excessively smoothed out) in the retail price face by consumers
* increase the confidence of retailers entering the market and encourage the development of more innovative retail tariff offers (chapter 12)
* assist distribution businesses to understand the potential problems that changes to network tariffs could impose on retailers (box 11.5).

Similarly, a formal requirement for distribution businesses and retailers to engage with consumers is important to ensure that consumers are well placed to respond appropriately to time-based pricing; are aware of the implications for their electricity bills; and are aware of the support mechanisms in the event that the new pricing regime will create financial difficulties for them. More specifically, such engagement and education should encompass the timing and benefits of smart meter installation; the basis for the different components of time-based prices; the timetable for steps in the transition to the new pricing regime; the way in which consumers will be advised of critical peak pricing events; and the various options available to consumers to better manage their demand.

|  |
| --- |
| Box 11.5 Ameliorating the transitional costs for retailers |
| Retailers already have to deal with different network tariffs applying across customer classes and the service areas of distribution businesses. However, with cost-reflective, time-based network pricing, the complexity of the price formulation process would increase and with it, the administrative costs of reflecting those prices in retail tariffs. (The operation of a centralised smart meter data management system could help to lessen, though not eliminate, this additional administrative burden for retailers.)  Adequately advanced notice of network pricing changes to retailers is important. There is a requirement that distribution network businesses update a ‘statement of expected price trends’ for each regulatory year (cl. 6.18.9(3) of the Rules). However, prior to an *actual* change in network tariffs, retailers only need to be given 20 business days’ notice. In the absence of earlier engagement, such short notice would make a smooth transition to time-based pricing difficult for retailers and their customers. Indeed, the sort of engagement catered for by this rule is seemingly reflective of minor adjustments to pricing regimes than the sort required for major pricing reforms.  A critical issue is whether retail price deregulation and the capacity for cost-reflective prices would result in exposure by consumers to the enormous fluctuations in wholesale energy prices that can sometimes occur (up to $12 900 per MWh or $12.90 per kW). Of course, such high pricing events do not occur often, and they usually do so for only short periods. Regardless, even if permitted to adopt cost-reflective prices for wholesale energy variations, it is unlikely that retailers would change their current practice of hedging, or contracting with generators (thus smoothing of price volatility in the wholesale energy market) for residential customers. This is because such events are not predictable — but can arise from generator failure, strategic behaviour by generators and transmission failures at any time. Consequently, it would be hard to pre-notify consumers of such pricing events. Nor is it clear that where the pricing events result from such unpredictable events (compared with the predictably high costs associated with network capacity built for the hottest days) that it would be efficient to pass on these volatile unhedged wholesale prices to consumers. Consumers value insurance for such unpredictable events. A retailer that failed to provide such a service would be unlikely to retain customers. Large energy users fall into a different category — and will sometimes agree (with the possible involvement of an intermediary) to voluntary load shedding in return for a fee during high price events, thus lowering their overall costs. Such firms or their intermediaries have the facility to continuously monitor five-minute interval wholesale electricity prices and have the ability to take very rapid action to curtail consumption. Households are unlikely (even with the aid of an intermediary) to ever be able to respond in this sort of manner. |
|  |
|  |

Recommendation 11.9

The Australian Energy Regulator should require:

* distribution businesses to demonstrate that they have actively engaged with retailers very early in the development of new time-based pricing structures, including on ways to incorporate those charges in retail prices to clearly signal to customers the costs of meeting peak network demand
* distributors and retailers to demonstrate that they have engaged with, and educated, customers prior to the introduction of smart meters, and again prior to the introduction of new time-based tariffs. Such engagement should occur sufficiently early to ensure that customers have been:
* ***given sufficient information and time to respond appropriately to time-based pricing (including of the various means to manage their peak demand)***
* ***informed about the implications for their electricity bills***
* ***given clear guidance about the way in which advance warning of critical peak pricing events will be communicated***
* ***provided with support mechanisms in the event that the new pricing regime creates financial difficulties for them.***

1. In chapter 19, the Commission recommends various changes to achieve more efficient charges for transmission network services. However, the broad underlying goal is the same as for time-based pricing for distribution networks considered in this chapter. [↑](#footnote-ref-1)
2. For example, Sergici and Faruqui (2011, p. 13) and Frontier Economics and Sustainability First (2012, pp. 32‑3). [↑](#footnote-ref-2)
3. Even where the technology supports TOU pricing, its uptake appears relatively low. The ENA noted that only around 30 per cent of customers using interval meters in New South Wales choose a TOU tariff (trans. p. 335) — but this may partly reflect the fact that untargeted TOU tariffs do not create much of an incentive to vary usage by time. [↑](#footnote-ref-3)
4. This and other references in this chapter to particular clauses refer to version 54 of the Rules. [↑](#footnote-ref-4)
5. This margin is even wider if the ambiguity and problems in defining both bounds are considered. This is highlighted by the examples of calculations of stand-alone costs given by Turvey (2000b, pp. 42‑3), who characterises it as lacking all practical interest. ETSA Utilities (2011) revealed many of the difficulties in its calculation. [↑](#footnote-ref-5)
6. As spelt out in clause 6.18.4. In practice, it excludes geographic location (although the Rules would allow it). [↑](#footnote-ref-6)
7. Many participants and others have also made this point (Deloitte 2012, p. 20; AEMC 2012u, pp. 181ff). [↑](#footnote-ref-7)
8. ‘Lumpy’ network investments are large forward-looking investments made at infrequent intervals, usually associated with some significant step upgrading of the capacity or reliability of the network. [↑](#footnote-ref-8)
9. These include marginal incremental costs (MIC), average incremental costs (AIC), and long-run incremental costs (LRIC). [↑](#footnote-ref-9)
10. This is not novel. The pricing arrangements set out in the Rules for transmission services (clause 6A.23.4(e)) indicate that prices for recovering the locational component of providing prescribed Transmission Use of System services *must* be based on demand at times of greatest utilisation of the transmission network and for which network investment is most likely to be contemplated. [↑](#footnote-ref-10)
11. In its final Power of Choice report, the AEMC (2012u, p. 282) reached the same conclusion. [↑](#footnote-ref-11)
12. And depending on the precise methodology adopted to calculate LRMC. [↑](#footnote-ref-12)
13. Among these are Colebourne (2010), ETSA (2012a), Futura (2009), Oakley Greenwood (2010b) and the many estimates cited by Deloitte (2012). The Commission used these to estimate some of the benefits of various demand management options (chapter 9). There are few publicly available estimates for transmission networks. [↑](#footnote-ref-13)
14. The Power of Choice review ‘… considers that there is scope to better enable AEMO to perform its responsibilities with respect to demand forecasting, and to improve its ability to forecast price responsive DSP [demand side participation] in the NEM’ (AEMC 2012u, p. 142). The Commission would expect AER and AEMO to cooperate in pursuit of improved demand forecasting capabilities under a cost-reflective, time-based pricing regime. [↑](#footnote-ref-14)
15. The Power of Choice review also proposed that National Electricity Rules distribution pricing principles be amended to provide better guidance for setting efficient, flexible network price structures and the AER develop and publish a guideline for network tariff arrangements (AEMC 2012u, p. 181). [↑](#footnote-ref-15)
16. The AEMC (2012, p. 173) only proposed this opt-in model for low energy using consumers and businesses (so-called ‘band 3’ customers). It proposed that large residential and small business consumers above a defined annual consumption threshold (band 1 customers) be required to have an efficient and flexible network tariff as part of their retail price offer. Finally, it proposed an opt-out model for customers with an annual consumption level below the band 1 threshold but above the band 3 threshold. [↑](#footnote-ref-16)