INTRODUCTION

In recent years, demand growth on Australian networks has been high, requiring additional capital expenditure to maintain acceptable standards of supply. In EnergyAustralia’s case, capital expenditure over the 2004-2009 period of the current regulatory Determination is expected to increase three-fold over the previous Determination, with the major factor driving this increase being demand growth. There is thus increased emphasis by Networks on managing demand, and increasing encouragement by Australian Regulators for them to do so. Efficient infrastructure pricing serves to directly influence customer behaviour and forms a foundation for other demand management options.

NETWORK PRICING IN PERSPECTIVE

A factor which is relevant to the development of both infrastructure pricing and demand management initiatives is the structure of the organisations which form the national Grid, supplying electricity to the Eastern portion of Australia.

The formerly integrated organisations were split up during the mid and late 1990’s, to facilitate competition in a National Electricity Market (NEM). Contestability has been introduced wherever feasible, to provide incentives for efficient operation. The significance of this industry disaggregation is that although pricing and demand management initiatives may have beneficial effects throughout the whole supply chain, the incentive driving each business is to improve its financial position within its business sector. No one industry participant is in a position to capture the full benefit arising from pricing or demand management measures and thereby prepared to invest up to the economic cost of implementation. Incentives are thus required to stimulate participation in economic investment.

The price signals imposed by network businesses are passed on to the customer via retailers, who may not choose to directly reflect network price signals in their retail tariffs. For example, retail “bill smoothing” plans may serve to mute network price signals. Despite this, the network price signals are expected to elicit some response by retailers in order to mitigate the risks that would otherwise be imposed on them.

PRICING AND DEMAND MANAGEMENT

Network price structures can play a significant role in encouraging sustainable infrastructure development, sustainable energy usage and the development of energy efficient technology. The forms of pricing and demand management can be considered as three categories, as follows [1]:

- **Environmentally driven.** Mainly aimed at encouraging reduced overall energy consumption or fuel substitution.
- **Energy Market driven.** Aimed at reducing energy purchase costs by reducing energy consumption in high price periods, possibly by transferring consumption to lower price periods.
- **Network driven.** Aimed at reducing capital expenditure on the network by reducing demand during periods of network congestion, possibly by transferring consumption to periods of lower network loading.

The three forms of pricing and demand management and their interrelationships are depicted in Figure 1.

![Figure 1 Types of pricing and demand management](image)

**Figure 1** Types of pricing and demand management

The essential points to be made concerning Figure 1 are as follows:

- Environmental options, which encourage an overall reduction in consumption, are unlikely to have a great effect either on high energy market prices or network congestion, both of which have a duration of a few tens of hours per annum.
- The converse also applies, in that measures targeted to reduce consumption during network and market peak periods are unlikely to have much effect on overall consumption.
- Furthermore, as will be demonstrated, there is a poor degree of correlation in the Australian market between network congestion periods and periods of high energy market price, which restricts the available opportunities for a combined solution.

WHY HAVE COST REFLECTIVE PRICING?

Changes in the pattern of network loading

Overall, the growth in energy consumption in EnergyAustralia’s region (which includes two thirds of Sydney) has been 2.7% per annum during the period since 1996 (which includes the Olympics build up). Of more significance, however, has been the disproportionate growth in summer demand, which has averaged 4.3% per annum. This is significantly greater than the corresponding winter growth of 1.8%. These statistics reflect the impact of a significant change in the penetration and use of air conditioning. It is estimated that 48% of residential customers’ premises were air conditioned in 2003/04, compared with 31%
in 1997/98. The air conditioning load is predominantly in the
domestic and small business sectors.

Figure 2 illustrates the effect of air conditioning usage on the
average customer demand profile. As might be expected, there
is little discernible change in the pattern of summer consumption
in non-air conditioned premises in hot weather. In contrast, the
average air conditioned premise tends to be somewhat larger and
have a higher base consumption, but the peak consumption
increases dramatically in hot weather.

Figure 2  Effect of air conditioning on domestic consumption
Summer consumption is at its highest from 14:00 to 18:00 hours,
the period when high summer ambient temperatures adversely
affect the capacity of network equipment.

Moreover, as the load factor of domestic air conditioners is less
than 10%, their owners do not pay an equitable share of network
augmentation costs through tariffs based on anytime energy.

Efficiency objectives of network infrastructure pricing

The pricing of network infrastructure is a significant component
of the cost of delivered energy to customers, averaging about
40% but sometimes having a greater impact than the energy
cost component. This section explains the principal network pricing
objectives.

It is important to distinguish between the fixed and marginal
costs of operating and maintaining an electricity network. Fixed
costs are independent of the load, whilst marginal costs are
associated with carrying the next increment of load. It is also
necessary to distinguish between short and long run marginal
costs.

Short Run Marginal Cost (SRMC). Applies to a period where
no new infrastructure investment is provided. Network short run
marginal costs are very small. The infrastructure is in place and
it costs little extra to carry a marginal increase in energy or
demand, although sometimes operating expenditures can be
increased through impaired access for equipment maintenance.
Increased short run costs in the supply chain are limited to
electrical losses and the cost of out-of-merit generation, where
the capacity of the network constrains the lowest cost generation
from being dispatched. However, both of these costs are traded
within the Australian NEM as part of the energy cost, rather than
being reflected in the network price.

Long Run Marginal Cost (LRMC). Is evaluated over a period
including future augmentation of the network. The Net Present
Value (NPV) of the future investment and its associated
operating cost are spread over the accompanying increase in
demand or energy. This results in an average LRMC, as follows:

\[
\text{NetworkLRMC} = \frac{\text{NPV}\left(\text{growth related capital cost} + \text{incremental operating costs}\right)}{\text{NPV}\left(\text{incremental energy or demand consumption}\right)}
\]

In the case of EnergyAustralia, this LRMC is some 80% of the
average network price, which represents the revenue deemed
necessary by the regulator to sustain the network business. The
percentage varies between customer classes.

Network assets have long lives, generally in excess of 30 years,
and often, lengthy construction times. Network augmentation is
thus extremely ‘lumpy’, as there are large, high cost investments
at irregular intervals. Pricing of network service on a long run
basis is appropriate to this situation. This approach provides a
relatively stable price signal to customers on which they can
base their plant and appliance investment decisions.

This marginal cost approach is important in achieving allocative
efficiency but there is also a need to recover fixed costs, as the
marginal cost alone would not recover sufficient revenue.

In summary, an efficient network price would have at least two
parts and should:
- Pass on the LRMC of network costs to the customers as a
  price-signalling component;
- Recover the balance of network costs in the least
distortionary possible way (preferably as a fixed cost, but
  failing that, through anytime energy); and
- Be structured in the simplest possible way, so as to facilitate
  customers’ consumption and investment decisions being
  related to their bill.

Whilst basic network tariffs should be structured in this way,
there are potentially short-term pricing options available to target
specific high cost events and so lead to further overall economies
in the supply chain.

PRICING AND DEMAND MANAGEMENT

An analysis of the potential effect on customers of delivering
demand management through pricing follows. In determining
network costs, the LRMC has been allocated to periods of peak
loading. The relative capacity limitations of network equipment
in winter and summer periods have also been taken into account.

Figure 3 charts the network load, pool price and allocated
network cost over the five-year period to June 2004 (the lower
two charts are on a logarithmic scale).

The following points may be drawn from Figure 3:
- The weekly and seasonal variation, including the incidence
  of public holidays at Christmas and Easter, may be
  identified. There is greater variability and higher demand in
summer (Dec-Jan-Feb in the southern hemisphere), and to a lesser extent, winter (June-July-Aug);

- Hourly average pool prices also display great volatility. The cap on NSW pool prices in any five-minute settlement period was $10,000/MWh, whereas the average price was $A37.70/MWh. This great range of pool price is a feature of the Australian energy-only market settlement arrangements.
- The network cost driver is strongly seasonal, largely reflecting the summer and winter periods of higher demand, with significant volatility.

It is also evident from Figure 3 that there is limited correlation between the pool price (which is driven by the interplay of generation and network availability, bid prices and customer demand) and periods of high network cost (driven solely by high demand). This poor correlation leads to an $R^2$ value of 0.29 between the daily peak load and pool price.

Australia’s gross pool market framework and companion contract market, presents significant challenges to launching a successful coordinated pricing demand response program along the lines of international pioneers. Studies have shown that customer demand response capability is driven by predictable pricing patterns, and that Australian wholesale energy pricing patterns will make developing any demand response program a challenge.

**Time of Use/Seasonal pricing.** The rationale for ToU and Seasonal pricing for networks may be understood by reference to Figure 4, which is based on the network cost allocation.

**Critical peak pricing.** Four types of critical peak pricing have been considered. Apart from requiring interval metering, this form of pricing is dependent upon the availability of a communications channel and display unit, to signal periods of high price to the customer. The options chosen for this analysis are:

- Critical peak 30, in which the peak period would target the top 30 hours of:
  - network peak loading;
  - pool price; and
  - both network peak loading and pool price; and
- Critical peak 50, in which the peak period would target the top 50 hours of both network loading and high pool price.

These pricing options are inset in the right hand side of Figure 5. For critical peak prices, the peak rates are significantly less than the cost reflective rates, which were considered to be unacceptably high. The cost reflective Critical peak 30 rate of up to $A3,700/MWh was moderated to $A2,000/MWh.

**Electrical losses.** An aspect of cost arising from the use of the network, which has also been taken into account in the analysis is the variation of electrical network losses with loading.

Distribution loss factors are used to uplift energy measured at the customer’s meter to the points of market settlement, which are at the connection to the transmission network. The variation in distribution losses thus affects the energy purchase quantities.

**EFFECT OF PRICING ON CUSTOMER BEHAVIOUR**

The effect of pricing on customer consumption patterns is governed by the elasticity of demand – the effect that a price increase will have in reducing demand, or conversely a price reduction will have in increasing demand.

There is some level of uncertainty associated with the price elasticity of customer demand. It is also intuitive, and apparent from some studies, that the elasticity of customer demand can vary, with significant differences between long and short run.
effects. This occurs as customer short-term preferences are translated into longer-term decisions on appliance and plant stock, building standards and other conservation measures.

**Australian studies.** The National Institute of Economic and Industry Research (NIEIR) has assessed the long run price elasticity of electricity consumption for use by the National Electricity Market Management Company (NEMMCO) in planning the transmission network. Their assessment is that the long term price elasticity for New South Wales has a range of -0.22 to -0.52, with a mean of -0.37 [2].

Other available NSW documentation relates to the manufacturing sector, where processes and plant are generally long term in nature, but where inter fuel substitution may be more readily available. In a 1998 study, the then Department of Energy concluded that the elasticity across a range of business sectors ranged from 0.52 to -1.05 [3].

**Overseas studies.** There is a significant body of published work dealing with the topic of demand elasticity. This is referenced in the bibliography [4] - [17].

None of these studies is believed to assess long run elasticities adequately for the current situation in Australia, particularly given the significant recent penetration of air conditioning.

The main issues with respect to demand elasticities in electricity may be summarised as follows:

- There is a level of demand elasticity which can be exploited using appropriate price signals;
- The amount of load that can be reduced during peak periods is not just dependent on the elasticity, but also the size of the price spike used to elicit that demand response; and
- Education is important in eliciting demand response in electricity in the small end user market, more so than with other commodities. In many studies it is not clear that customers have been furnished with sufficient information to maximise demand response.

**Assumed price elasticity of demand.** For the purpose of the analysis in this report, an initial value of -0.12 was assumed in the first year, increasing to NIEIR’s average of -0.37 in the fifth and subsequent years of a 10-year analysis. It was also assumed that the differential in pricing between high and low price periods resulted in some reduction in demand and some load shifting behaviour. This was modelled by assuming the elasticity for off peak periods was 80% of that of the higher priced periods.

**Modelling of pricing outcomes.** The tariff structures described above have been combined with the price elasticities to estimate the effect on customers usage patterns. The impact on supply industry cost structures was estimated in four categories:

- **Network**, based on the reduction in capital expenditure or network LRMC;
- **Pool**, based on avoidance of high price periods. The pool price is not necessarily related to the average cost of energy generation (fuel, operating and capital) but rather the bid prices submitted by the operators of available plant. It should be noted that there is a “flow on” effect where a reduction in load at times of high pool price would lower the price for all customers. This effect has not been taken into account;
- **Long run generation costs.** For small NSW customers, the hedging rate between generators and retailers is pre determined. This arrangement is termed the Electricity Tariff Equalisation Fund (ETEF) and the associated Regulated Energy Cost (REC) has ToU rates set with regard to the long run costs of new entrant generation [18],[19].
  - **Greenhouse**, based on a cost associated with Carbon Dioxide emissions. An average rate of $15/Tonne of CO2 was used, together with an average conversion rate of 1 MWh per Tonne. The rates were applied to energy conserved, through direct reduction in consumption or through peak shifting, with energy consumed at periods of lower network losses [20].

The overall reduction in costs per customer arising from the pricing options (compared with a single rate tariff) is illustrated in Figure 6. The analysis is based upon an average customer annual consumption of 15 MWh, which corresponds to an annual retail bill of approximately $A1,600. This corresponds with the lower limit of customer size currently proposed by EnergyAustralia for its meter and ToU roll out. In the case of the critical peak options, it has conservatively been assumed that 50% of the available benefit could be captured, because of the difficulty of forecasting high price periods in advance.

For comparison with the cost reductions shown here in NPV terms, the NPV of the customer’s bill over the same 10-year period would be $A11,700, so that the Critical peak 30 tariff would provide a potential reduction in average costs of service in the vicinity of 40%.

**CONCLUSIONS**

The following observations are made concerning the network infrastructure pricing options that have been analysed in this report.

**Demand management effects of network pricing options.** Pricing options that target network constraint periods to reduce network capital expenditure deliver much smaller benefits in terms of pool price reduction or reduced energy purchase costs.

Cost reflective network pricing options also deliver very small benefits in terms of reduced overall consumption, and therefore greenhouse emissions.

ToU is a relatively straightforward form of pricing and on the basis of the assumed customer elasticities and costs, is expected on average to return the cost of investment in interval meters for customers of at least 15 MWh annual consumption. It can be observed from Figure 6 that a 3-rate ToU price is much more effective than 2-rate ToU. Seasonal pricing is a refinement of ToU, which for little additional complexity can double the expected benefits.
Critical peak pricing appears to offer the most favourable option for targeting consumption during network constraint periods. Whilst this option requires at least a one-way communications path (which might most economically be provided on a whole-of-network basis) and introduces additional complexity, it appears to be worthy of further investigation.

The Demand Management effects of cost reflective network pricing options can be summarised as follows:

- Simple price structures like the inclining block are limited in effectiveness and target overall consumption. There is a limited seasonal effect in that average consumption patterns are greater in Summer and Winter. This type of tariff does serve as a useful adjunct to more cost reflective pricing for larger customers.

- Time of Use and Seasonal pricing are expected to directly affect customers’ consumption, leading mainly to reduced consumption during peak periods. These cost reflective forms of pricing are also expected to support economical load management options such as the use of time switches and efficient appliance and building construction standards.

- Demand and Capacity changes have the potential to influence customer awareness and consumption patterns more directly. The monthly billing associated with these tariffs provides a more frequent reminder to customers of the cost of peak period consumption. Furthermore, kVA demand tariffs provide an incentive for customers to install power factor correction equipment.

- The critical peak pricing options most closely target peak periods and appears to offer the potential of very significant benefits in terms of both network cost and pool purchase energy costs. There is a trade-off between the network and pool benefit and the optimum outcome would target the high price periods of both. The Critical peak 50 pricing delivers lower gains than the Critical peak 30 option. This is because the peak rate is lower (spread over a greater number of hours) and customer response correspondingly reduced.

**A pricing experiment.** The analysis in this report indicates the desirability of conducting a pilot program to evaluate the systems and effectiveness of the critical peak form of pricing. One of the biggest advantages would be that through experimentation, a clearer view of the customers’ elasticity of demand would be obtained.

**Regulatory considerations.** It may be seen that about one quarter of the benefit from ToU pricing arises from energy cost savings, which are not captured by the network. Whilst it is clear that the major beneficiary of pricing would be the network, there is a strong case for the necessary investment in metering and systems to receive a regulatory allowance in order to facilitate it. The retail cost savings accrue within the contestable portion of the supply chain and in this competitive environment may reasonably be expected to flow through to customers.

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**BIBLIOGRAPHY**


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