Efficient Network Pricing and Demand Management

Prepared for IPART by
East Cape Pty Ltd

INDEPENDENT PRICING AND REGULATORY TRIBUNAL
OF NEW SOUTH WALES

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Request for Submissions

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Submissions must be made in writing and should be sent to the postal address, fax number of email address below on Friday April 5, 2002. Where possible submission should be provided in a computer readable format (eg, word processor, PDF or spreadsheet) either on disk or by email.

Inquiry into the Role of Demand Management and Other Options
in the Provision of Energy Services (Matter No. 01/257)
Independent Pricing and Regulatory Tribunal
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This report was commissioned by the Independent Pricing and Regulatory Tribunal. The views expressed here are those of the author alone and do not reflect the position of IPART or the New South Wales Government. The author of this report is East Cape Pty Ltd.

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FOREWORD

In recent times, high and volatile prices for electricity, generation capacity constraints, and concerns about the environmental impacts of electricity generation has led to increased interest in strategies to manage the timing and level of consumer demand for electricity.

The Premier has asked the Independent Pricing and Regulatory Tribunal to undertake an inquiry into what role Demand Management should play in providing the state's energy services. This Paper on Efficient Network Pricing is a part of this Inquiry and addresses the significant issue of whether better pricing signals and structures could be employed in NSW to bring about better Demand Management outcomes. The Tribunal has employed the services of Mr Philip Theaker of East Cape Pty Ltd to prepare this Paper.

A key issue is whether energy prices at all stages of supply (generation, transmission, distribution and retail) appropriately reflect all relevant costs. Pricing of network services is only one element of this issue. However, it is important because it is subject to ongoing regulation due to its 'natural' monopoly nature and hence is not subject to the discipline imposed by the market. Network pricing structures can influence the location of distributed generation and affect incentives for demand management.

It is apparent that, at least in theory, it is possible to establish complex and highly targeted price structures to achieve efficient network price signals. However, perhaps more importantly, efficient pricing strategies need to be integrated with the investment and corporate strategies of the network owner. The interrelationship between current pricing signals and more efficient utilisation of the network and future investment requirements must be recognised.

The Tribunal's view is that it is difficult for a Regulator to mandate specific price structures. The Regulator cannot possess the in-depth knowledge of the network business and its customers which the network owner has. Thus the Tribunal believes that responsibility for establishing appropriate price structures and signals rests primarily with the network owner. Nevertheless, the Tribunal acknowledges that it can provide greater guidance on price structures and signals through the pricing principles it publishes in relation to network pricing - the Pricing Principles and Methodologies for Prescribed Electricity Distribution Services.[1]

The Tribunal recognises that any change in network pricing structures to create better targeted, locational signalling would be a significant change from current practices. To achieve this, the Tribunal is interested in the idea of trials of locational and congestion pricing structures by the distribution businesses, and invites specific proposals for these types of trials from the industry. These could complement the initiatives to enhance the role of demand-based charges already proposed by DNSPs.

The Tribunal welcomes your comments on these and other matters raised in this Paper.

Thomas G Parry
Chairman
February 2002

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1 IPART, *Regulation of New South Wales Electricity Distribution Networks, Pricing Principles and Methodologies for Prescribed Electricity Distribution Services, Developed pursuant to clause 6.11(e) of Part E, Chapter 6 of the Code*, March 2001.

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1 INTRODUCTION

The Tribunal's current inquiry into demand management (DM) and other energy service options[2] provides the context for this discussion of distribution network pricing. That network pricing practices may influence the take up of DM was one of the questions raised by the Tribunal in its Issues Paper.[3]

The key question posed by this inquiry, and the Tribunal's earlier Issues Paper, is whether demand management options that can meet customers' energy needs at lower cost and, possibly, with better environmental outcomes, are being by-passed in favour of 'build and generate' options.

An important subsidiary question is whether energy prices (ie prices for the production/generation, transmission, distribution and retail supply) properly reflect all relevant costs at each stage of supply. The pricing problem is made more difficult because costs can vary considerably by time-of-use and location. Pricing can be a significant barrier if those parties - such as generators, distributors, retailers, energy service companies and end-users - who can respond through demand management and distributed generation options, are not provided with appropriate pricing signals.

The pricing of network services is only one element of the energy pricing problem. However, it is an important one because:

- network prices constitute about 50 per cent of the cost of delivered energy for most customers but are regulated and not subject to the same market disciplines as other cost components
- network costs can vary significantly by location and the efficient signalling of such costs can have a major impact on the viability and take-up of distributed generation and demand management.

This paper focuses on network pricing and its relationship to demand management and distributed generation. The subject is approached by looking at the broader issue of the relationship between network services, the pricing of those services and the development of an energy services market. Demand side responses and distributed generation form a key part of that market.

From the discussion five conclusions emerge:

- distribution networks are part of the energy services market, and should be treated as such
- as in any market, pricing has a critical influence on bringing forward the least cost combination of supply and demand responses; distribution network pricing is no exception
- pricing should form an integral part of DNSP network planning and investment
- efficient pricing is a useful concept, but to be practical, priorities must be set

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2 The Premier has asked the Tribunal to undertake an inquiry into the role of demand management in meeting the requirement for energy services in NSW. The inquiry's terms of reference may be viewed on the IPART website.

3 IPART, *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services, Issues Paper*, DP47, July 2001.

- while regulation can help set those priorities, the value of more prescriptive price control is questionable.

1.1 A market for energy services

Very few customers require electricity for its own sake. Most use it in combination with appliances and equipment to provide energy services such as lighting and temperature control and to run commercial and industrial processes. Their use of electricity – the volume they consume, their maximum demand and the pattern of use hour by hour – is the end result of a series of choices they make about how they can best meet their energy service needs. Customers make these choices directly and through energy retailers, based on the information available to them. This information includes the purchase costs, the energy costs, the expected performance of the equipment, the alternatives available and so on.

The resulting demand for electricity is met in two stages – firstly through the generation of electricity and secondly through its transport over the electricity network to the location at which it will be used. Here again there are choices to be made as to the type of generation to use, whether it should be sited close to customers thus saving on transport costs and so on. Some large customers or other interested parties may consider generating their own electricity locally to avoid high transport costs for example or to take advantage of by-products from their industrial operations that can be used to generate electricity at lower cost.

A key input to choices on both the demand and supply sides is cost – if costs are not known or are under or over stated then the choices made may be wasteful, using resources that could be better used elsewhere. Electricity usage and transport (network) prices that reflect all relevant costs allow unbiased comparisons to be made between alternative ways of meeting customers' energy service needs. Such choices can be made directly by customers or by agents such as retailers and energy service companies acting on behalf of customers.

When information on costs is made available, the lowest cost options that provide the required services can be selected. These may be on the demand side - for example, reducing electricity use by investing in energy efficiency or shifting demand from high cost to low cost periods – or on the supply side, such as the use of distributed (local) generation or cogeneration. It also creates business opportunities for the development of products and services directed at optimising customers' use of electricity or taking advantage of lower cost supply options.

This situation - where customers or their agents see prices that reflect all relevant costs that their consumption imposes and make choices from a range of alternatives – is what happens in a market. While the main commodity under consideration is electricity, the focus of this market is the customer's energy service needs.

Box 1 Network service, demand side responses and distributed generation

Electricity networks are a transport system; they link sources of generation to points of consumption (or load). While load is widely dispersed, determined by the spread of population and industry, most electricity is generated in a few large power stations.

Electricity consumption varies considerably during the day. Peak demand usually occurs on summer afternoons and winter evenings. Generation and network capacity must be capable of meeting these peaks with acceptable levels of reliability, even though this means that a large proportion remains unused for the rest of the time. Peak demand is therefore a major driver of electricity costs.

If parts of the network become congested through heavy use, reliability falls and the chances of prolonged interruptions to supply increase. There are three main remedies – the capacity of the lines can be increased (network investment), demand during periods of congestion can be reduced (demand side response) or a new source of generation can be added that takes load away from the congested lines (distributed or local generation).

Network prices, by signalling the cost of congestion (the cost of the investment in additional capacity required to relieve the congestion) can play a key role in providing incentives for demand side and distributed generation responses. These responses may be more economic than the network investment option, resulting in lower costs for customers. Responses may come from DNSPs, energy service companies, proponents of DM technologies and processes, customers or any other interested parties.

Currently, the market for responding to these signals in ways other than applying conventional network investment principles is poorly developed.

Network prices that mask the costs of congestion impair the emergence of demand side and distributed generation responses and can lead to inefficient investment decisions and increased costs for customers.

1.2 Issues for submissions

This is one of a number of papers that will canvas issues relevant to the Tribunal's current Inquiry into demand management and other energy service options. The Tribunal wishes to encourage discussion and invites interested parties to comment, in writing, on the issues raised.

The key question posed by the Inquiry is whether demand management options that can meet customers energy needs at lower cost and, possibly, with better environmental outcomes, are being by-passed in favour of 'build and generate' options. In relation to network pricing, the key issue is whether energy prices (ie prices for production/generation, transmission, distribution and retail supply) properly reflect all relevant costs at each stage of supply.

In particular, IPART seeks your views on the following issues:

1. What is the desirability of:
   - Continuing the Tribunal's current Pricing Principles and Methodologies (PPM)?
   - Augmenting the PPM along the lines proposed in section 6.2.1?
   - Augmenting the PPM along the lines proposed in section 6.2.2?

   If changes to the PPM are supported, it would be helpful if drafts of the proposed changes are provided in your submission.

2. What is the practicality of congestion-related pricing or other demand-based pricing strategies at the Distribution and Transmission level — for example, congestion period usage charges or rebates applied uniformly or by location?

3. What are the options for the DNSPs (working with any other interested parties) to develop trials of such congestion pricing approaches — for example, by focusing on network areas that are close to or will reach capacity in 3-5 years?

4. What are the priorities for price signalling – that is, what are the practical and immediate steps that can be taken.

5. What steps can be taken to improve the development of price-supporting infrastructure — for example, metering, communications and control systems?

2 THE INDUSTRY CONTEXT – MARKETS AND ELECTRICITY

Over the last 10 years or so the structure of the electricity supply industry in Australia has undergone a fundamental shift. Within the generation sector, State-based regulated monopolies have been replaced by a commodity-style spot market, in which electrical energy is priced and traded to meet demand on a half-hourly basis. The market is open; decisions to enter or leave are made on the basis of individual assessments of risk and future returns. To hedge their price and volume exposures, participants employ a range of risk management devices that originated in financial and commodity markets.

A similar shift is occurring in the supply of electricity by retailers to end-users. One large consumer (Yamasa Seafood Australia Pty Ltd) is currently buying 'direct' by participating in the wholesale market, and more 'direct' customers are expected to emerge over time. However, most consumers take their supply from retailers. Retail franchises, which underpinned the old industry structure, are now being progressively wound back. A retail market is developing in which consumers are free to choose their preferred supplier.

To a large extent, the pre-existing industry structure based on central planning and control had developed in response to the physical properties of the electrical system. The recent restructuring has been a consequence of a collective decision by governments to instead apply a market-based economic model.[4] The physical properties of the electrical system remain the same, but the concepts around which it is organised are economic. The broad aim is for electricity to be produced and supplied through the operation of markets. When markets work efficiently, goods and services are produced to meet the demand from consumers at the lowest economic cost.

Questions of market efficiency are central to the debate in electricity industry restructuring here and overseas:

- How far can markets be used to price and transact the physical elements required for the operation of an electrical system and to meet customer demands?
- What are the conditions for efficient market operation and how can they be met?
- Will the economic signals from the market elicit investment responses on both the supply and demand sides?

As experience with the use of markets within the industry grows, it provides a basis for the refinement of trading arrangements and their progressive extension into areas of regulated supply. Network service is one such area.

[4] This market, which covers the eastern states, is collectively known as the National Electricity Market, or NEM.

3 MARKETS AND NETWORK SERVICE

Networks provide the physical link that allows the transport of electricity between points of generation and points of consumption. The price of electricity delivered to the consumer is made up of the energy cost determined by the bid prices of generators in the half-hourly spot market, the transport cost and the retail margin. For electricity to be delivered to consumers at the lowest economic cost, the overall costs must be minimised, principally that of the energy and transport components.

Box 2 Network costs[5] and the investment decision[6]

In the short run, when capacity is fixed, network costs are made up of energy losses and the cost of capacity constraints. Where constraints occur, costs may be incurred through the use of out of merit generation, leading to a higher energy price, or through a reduced supply quality or interruptions to supply. In the long run, capacity can be expanded and network costs will be determined by the costs of maintaining and adding to the network.

Where there is a constraint it will be economic to add network capacity if the cost of construction is less than the cost of the alternatives – additional generation or demand management. Additional capacity will continue to be economic up to the point at which the cost of an extra unit (long run marginal cost or LRMC) will be equal to the cost of constrained out of merit generation, network losses, reduced quality of supply and interruptions (short run marginal cost or SRMC).

Distributed generation or DM options will be economic if their costs are less than the total avoided energy and network costs of generation/network investment options for similar levels of service.

For optimal network use and investment, consumers and investors (including proponents of DM services and distributed generation as well as DNSPs and large scale generators) must face prices that reflect these costs (prices that are economically efficient). Where a mechanism is available that allows efficient price discovery either side of a network constraint, there will be scope for responses to be market-based, opening the way for entrepreneurial action be generation, network and demand-side participants.[7]

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5 Network costs in this discussion exclude any externalities that may be present – section 5.5 considers externalities and the issues involved in placing a value on them.

6 This overview is based in part on Houston G, *Electricity Transmission Pricing and Investment*, NERA, Sydney, August 2001.

7 The new NSW Demand Management Code (*NSW Code of Practice, Demand Management for Electricity Distributors*, 18 May 2001) emphasises the market-based development of options for electricity system support (including demand management, distributed generation and storage options) and their evaluation at the same time and in the same manner as network investments.

3.1 Transmission

The development of market-based approaches to network pricing and investment, where prices are set by the interaction of supply and demand and investment decisions are made by market participants rather than a planning authority, have to date focussed primarily on the transmission sector.[8] Transmission assets combine with sources of generation to create an integrated and interdependent system for delivering bulk electricity.[9] In principle, because generation capacity and loads are spatially dispersed, energy prices set in the spot market may vary by location. Transmission system performance (via the effect of losses and constraints) will affect these prices. Consequently, the representation of transmission networks in commercial electricity trading has become an important issue in market design.

Currently the level of integration of transmission services within electricity markets is quite limited. In the absence of an effective trading mechanism, industry regulators have taken on the responsibility of administering transmission prices. The efficiency of the pricing signals provided to network users depends on the success of the regulator in applying pricing methods that accurately replicate the economic costs of network use.

On economic grounds there is a strong case for closer integration of the transmission sector within the commercial processes of the wholesale energy market. Most regulators and market administrators both in Australia and overseas have recognised this and support closer integration. There are complex issues to be resolved however - in particular, the difficulty of accurately representing physical electricity flows and system conditions in commercial trading models. As a consequence movement away from administered to market-based transmission pricing and investment has been gradual.

NECA and the ACCC have been reviewing the scope for an extension of market-based network pricing and investment within the National Electricity Market (NEM) for some time. Both agencies have supported a greater role for market-based responses to supply/demand imbalances and network constraints. The most recent expression of this has been the September 2001 determination by the ACCC on network pricing and market network service providers.[10] Areas of particular interest include:

- the benefits of an increase in the number of NEM regions and spot market pricing nodes
- for intra-regional transmission elements, the development of regulated usage prices that more effectively signal the cost of losses and constraints
- connection charges for new transmission assets that more closely reflect the benefits provided to generators
- the more effective provision of information to the market on current and expected future network conditions, including demand and capacity levels, service performance and maintenance requirements

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8 For more background on market-based approaches to transmission pricing and investment (eg nodal pricing, financial transmission rights, flowgate models) see the various reports published by NECA and the ACCC as part of the recent reviews of transmission pricing and investment and energy market integration, as well as Houston, *op. cit*, and the excellent work of Hugh Outhred from the University of New South Wales. Also, in the United States, a market-based approach has been successfully implemented in the Pennsylvania-New Jersey-Marylands electricity system.

9 See Ch 10 of the NEC for the definition of transmission..

10 ACCC, *Amendments to the National Electricity Code - Network pricing and market network service providers*, 21 September 2001.

- increased opportunity for market-based responses to network development, including entrepreneurial network investments, distributed generation and demand-side responses, through the use of more open planning and investment processes by Transmission Network Service Providers.

The outlook is for electricity provision, at both the wholesale and retail levels, to continue as a hybrid system in which commercial trading mechanisms are refined and extended, progressively replacing administered network prices and centrally planned decision making.

3.2 Distribution

In its submission to the Tribunal's Issues Paper, Country Energy claims that the promotion of time of use and demand time of use network prices is an integral component of its medium term network pricing strategy. However, in general less attention has been directed at the extension of market-based commercial processes to distribution networks. This reflects a number of factors, including:

- the priority placed on establishing an efficient wholesale market
- the greater level of commercial interest in generation and transmission investment opportunities
- the slower development of retail electricity markets
- the technical difficulties involved and
- the reluctance of DNSPs to move away from traditional forms of pricing, network planning and investment.

However, there is no obvious reason why the process of commercialisation should stop at the arbitrary boundary between transmission and distribution. To the contrary, there is a strong economic case for lifting the profile of market-based pricing and investment across distribution networks:

- the distribution network accounts for around 30 per cent of the final cost of delivered electricity; the cost of network investment – and therefore the importance of price signalling - is significant
- the large majority of electricity end-users receive supply through the distribution network, and hence receive their network usage price signals, including transmission costs, through distribution charges
- all of the major electricity market competitors to large scale generation (and hence also transmission networks) – distributed generation, cogeneration, demand-side bids and other demand management options – have their economics influenced by the performance and the pricing of network services
- in addition, a number of these alternatives to large scale generation also provide competition for distribution networks, by allowing end-users to get their electricity from on-site (or local) generation or by substituting demand management products for delivered electricity.

4 EFFICIENT DISTRIBUTION PRICE SIGNALS

In the transmission sector there are realistic prospects of progressively implementing a trading mechanism that will efficiently price network service and availability.[11] It would seem that the development of a market capable of producing efficient distribution prices is more remote.[12] In its absence there is a question as to what regulators can or should do to support efficient pricing. Before addressing this issue we must first consider in more detail the dimensions of efficient distribution network pricing and the factors that can influence its application in practice.

4.1 Signalling economic costs

Economically efficient pricing is a key issue for the development of market-based commercial processes within the distribution sector. Efficient prices signal the economic (marginal) cost of using the network. They provide incentives for optimal use of and investment in the network and its alternatives – demand side responses and distributed generation.

In the short run, when capacity is fixed, marginal costs will be made up of energy losses and the cost of network congestion. At present, congestion costs are incurred by customers in the form of reduced quality of supply and interruptions, rather than through increased prices.[13] Losses are a function of network configuration and the level of energy flows. In the long run when capacity is variable, the marginal cost is the investment in additional capacity that is required to meet an increase in demand on the network.

In the NEM the cost of distribution network system losses is incorporated into the energy price through volume adjustments and is not signalled through network charges. This leaves a major category of distribution cost without a distribution-based price signal.

Putting the issue of losses to one side, the economic costs of network use will vary with the level of capacity utilisation and by location:

- marginal costs will be low when there is spare capacity, since demand on the system can be increased with no loss of performance
- at higher levels of network use, additional demand will progressively reduce the quality and reliability of supply unless there is investment in new capacity
- investment costs will not be uniform across the network.

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11 Although opinions vary on how far this will go and over what timeframe.

12 Again, some analysts would caution against being too pessimistic. For example, in the US proposals are being developed that would extend market pricing to distributed generation and distribution network services (Lively, Mark B., "Fungible Distribution Tariffs: Supporting Distributed Generation without Bankrupting the Utility", *National Regulatory Research Institute Quarterly Bulletin*, Vol. 21, no. 3, pp 167-190).

13 Except where congestion at the transmission level results in the use of 'out-of-merit' generation.

4.2 Capacity signals

As the level of demand on network elements approaches their rated capacity, the reliability and quality of supply deteriorates. When demand approaches the capacity of the network to perform satisfactorily, then if service standards are to be maintained, either investment in additional capacity will be required to meet further increases in demand or some form of DM will need to be activated.

An efficient pricing signal for network use will have low demand charges when demand is low relative to available capacity and a demand charge that approaches LRMC when demand is at or close to available capacity. This reflects the probability of demand exceeding the capacity threshold for that part of the network, triggering the need for investment in additional capacity. As congestion increases and the capacity threshold is approached, the increase in price gives customers an incentive to reduce their demand on the network. The price signal does not have to be in the form of an increased charge. An alternative is to offer rebates for reducing demand (or providing local generation that has the same effect of reducing network use) at times of system peak.[14]

Box 3 Measuring demand on the network – real and reactive power

Electrical power has two components - real power and reactive power. Real power is the output that customers are interested in – useful work such as providing heat and motion. It is measured in kilo-Watts (kW). However, some of the equipment that does this work (such as electric motors and transformers) also depend on electric or magnetic fields for its operation. The generation of electric and magnetic fields requires reactive power, which is measured in kilo-Volt-Amperes – reactive (kVAr). Reactive power may either be provided through the network, or generated at the customer's premises.

The total power demand that the network is required to carry will be the sum of the real power required (kW) and the reactive power required (kVAr). Total demand is measured in kilo-Volt-Amperes (kVA).

The ratio of real demand (kW) to total demand (kVA) is called the power factor. A customer load with a power factor of 1.0 uses no reactive power. Most loads have power factors in the range 0.8 to 1.0. A load with a power factor of 0.8 would require the distribution system to be capable of providing 125 per cent of the real power (kW) used.

14 A similar alternative at times of system congestion is the use of agreements with customers that allow supply to be interrupted in return for a price discount. Controlled supply to water and space hearing appliances, for example, is fairly common and provides networks with some flexibility. More specific interruptible arrangements are less common, though some DNSPs are beginning to offer this service in relation to air conditioning and other peak-related equipment.

4.3 Locational signals

Capacity constraints may occur at different levels of the network and at different locations. The constraint may be within the transmission network, at the subtransmission level or at a particular distribution element. In addition, variations in terrain, customer density, distance from transmission nodes and other factors can lead to differences in LRMC across the distribution network.

Ideally network usage charges will signal locational variations in marginal costs. In practice there is significant complexity in accurately representing locational and time-specific marginal costs.

4.4 Transmission costs

Under current arrangements in the NEM, DNSPs pay regional transmission charges and then roll the costs into their distribution charges. Where transmission usage charges contain an economic price signal, which may be time-of-use, locational or both, they provide incentives for customers to use transmission services in a manner which balances the value of the service with its cost. Efficient distribution pricing requires that this signal is preserved and passed through to the customer.[15]

In NSW, there are currently six separate transmission charges applied to the DNSPs – according to the six distribution areas which existed prior to the amalgamation of Great Southern Energy, Advance Energy and NorthPower into Country Energy. These charges are applied under a revenue cap set by the ACCC and structured, under the existing Code Derogation,[16] so that revenue is recovered 50 per cent from fixed charges, 25 per cent energy charges and 25 per cent demand charges.

When the Derogation ends on 1 July 2002, TransGrid and EnergyAustralia will be required to apply full cost reflective pricing to the transmission system and they will also review the structure of their charges.[17]

Currently there are two spot market (energy supply) pricing nodes within NSW, with the prospect of more being added as the NEM develops. Because the energy price at a node reflects the cost of any transmission constraints encountered in delivering energy to that node, if the number of nodes in the NEM is increased, so will the scope for more accurate locational price signals.

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15 The network customer may be either an end-user of electricity or a retailer offering to provide electricity to an end-user.

16 This is a derogation which the NSW government negotiated with the ACCC, to enable the transition of transmission prices from the regime which existed in 1999 under the 1996 IPART Determination for transmission charges, to that imposed by the National Electricity Code.

17 This means that each connection point from the Transmission system to a customer or within a distribution area will have a separate transmission charge. For example, there will be more than 20 transmission connection points within the EnergyAustralia area. However, it is unlikely that these charges will properly signal capacity constraints and future augmentation requirements.

4.5 Network service as an intermediate good

While many of the larger end-use customers deal directly with DNSPs on connection and supply matters, the majority of small and medium-sized customers pay for their network service as part of a bundled retail price. This is a price management service offered by retailers. The retailer will make a commercial decision on the extent to which it passes through to the end user the costs of network service. Where the network charge is not directly passed through, the retailer in effect, absorbs some of the network price risk on behalf of the end use customer.

Provided that the retail market is competitive, the extent to which retailers can shield customers from network price risk will be limited. Retail margins are typically small. If the network price risk cannot be carried financially by the retailer it must either pass it through to the responsible customer, work with the customer to reduce their exposure to network price risk (through demand management options for example) or try to spread the risk over other customers. Spreading the risk would expose the retailer to the loss of those customers who would then be paying more than their true cost, and so would be difficult to sustain.

4.6 Demand response

Efficient network prices signal to customers the costs of their use of the network. The extent to which customers respond to price signals by seeking to adjust their level of use will depend on a number of factors. For example, the amount of electricity a customer uses, the pattern of consumption, their flexibility in timing and levels of consumption and the range of viable alternatives that are presented to them will all influence their price elasticity of demand.

Empirical studies indicate that many customers have an inelastic demand for electricity – their consumption of electricity shows little response to changes in price. This observation is sometimes used as an argument against the introduction of more efficient prices. The key issue for network pricing, however, is not the responsiveness of aggregate electricity consumption but time specific (and possibly location specific) maximum demand. This is a critical distinction.

Even with low demand elasticities, the scale of cost reflective peak to off-peak price differentials in a congested network could be expected to have a substantial impact on demand and capacity. Moreover, the price elasticity of peak demand is not necessarily constant over time or between customer groups. Price responsiveness is influenced by the size and frequency of the price movements that are experienced, the level of customer awareness and the range of responses that are available. Measures that encourage price responsiveness therefore often have a valuable role to play in market-based reform programs. This can be seen as a form of early market development.

It is important to have regard to the dynamics of the market. More sophisticated pricing structures may not flow through to end-users who may well prefer simpler prices. But such pricing may provide other opportunities and incentives. Using their information advantages, retailers and energy service companies can work with customers to manage their energy use by providing simpler price structures and more stable and lower total energy costs. If such approaches are successful – in terms of higher profits for retailers and energy service companies and lower costs for customers – they will stimulate greater interest in such options and increased responsiveness of demand.

Larger customers, with their bigger resource base, are likely to have a higher level of initial price responsiveness. As the largest energy users they are a particularly important source of congestion-reducing load management and, where production processes are compatible, cogeneration. While this suggests that they should be a priority segment of the market for efficient pricing, their load profiles are generally the flattest of all the customer groups. For large customers, the issue may be more one of load deferral at peak times and overall energy efficiency. It is the commercial and domestic segments of the market that contribute most to the 'spikiness' of demand.

5 LIMITATIONS ON EFFICIENT NETWORK PRICING

The economic principles that underpin the concept of efficient pricing seem relatively clear. In the absence of an effective market for network services the principles provide some general guidance for administering economically efficient usage charges. They emphasise the importance of signalling the marginal (or forward-looking) costs of network use, the relationship between capacity utilisation (or its corollary, the level of network congestion) and marginal cost and the time and location-specific nature of the cost signal.

However, the pricing of network services is a practical exercise that takes place in an environment of limited cost information, technical complexity and uncertainty. Prices have a broader function than signalling economic costs; they also recover the revenue necessary for financial viability and allocate sunk network costs between customers. On the other hand the financial costs that the network seeks to recover may not include any environmental and social costs that are associated with use of the network. Price changes may also impose adjustment costs on customers that are not taken into account when considering pricing efficiency in a narrow sense.

5.1 System complexity and cost signals

The purpose of capacity-related pricing is to signal to customers the costs imposed by their use of the network. As the level of available capacity shrinks the requirement for additional investment will increase. If customers see the investment cost reflected in their usage charge they will have an incentive to consider the value of their use of the network relative to other options for either meeting their energy service requirements or indeed reducing them.

However the relationship between customer use and network investment is rarely clear cut:

- capacity constraints may occur at any level within the distribution network, from low voltage reticulation to sub-transmission network elements and reflect consumption patterns of a group of customers
- the timing of demand peaks may vary at different levels within the network and by location
- the relationship between system performance and power flows over the network is often complex; in many cases capacity augmentations cannot be attributed to a single measure of demand for an individual customer or group of customers.

Where usage prices do not accurately represent the costs of network use, the efficiency of the price signal and the associated economic benefits will be reduced. Poorly structured prices may provide quite misleading signals and increase rather than reduce economic costs.

The selection of the most appropriate indicator of network marginal costs is therefore a key consideration. It will invariably involve a strategic assessment of the expected performance of the network over the medium term, the nature and cost of likely capacity constraints and the customer network usage patterns that contribute to the expected constraints.

In making this assessment some of the choices to be considered will include:

- the level of capacity signalling – whether this is system-wide or location-specific
- the form of capacity signalling, in particular the use of:
  - real power (kW) or real and reactive power (kVA) as a measure of demand placed on the network
  - anytime demand, preset time-of-use (hour, day, season), coincident demand or congestion-dependent time-of-use measures.

5.2 Information requirements

The availability of information on customer demand is a practical constraint on the structure of network prices. The cost and complexity of developing and administering more efficient prices must also be balanced against the expected economic benefits.

5.2.1 Metering

Capacity-related (kW or kVA) price signals and time of use energy pricing can only be considered where information on the level of demand placed on the network by customers and their consumption patterns over time can be measured.

Metering is a key issue for DM. A customer's response to network pricing will depend on the type of meter installed at the customer's premises. The costs of sophisticated metering will have to be balanced against the benefits of the additional information. The costs of sophisticated metering for small customers can prove to be excessive.

The meters required for customers with an annual consumption of more than 750 MWh (Type 3 meters) are capable of recording the customer's demand in kVA. Type 4 meters for customers that use more than 160 MWh a year record consumption on a half hourly basis and are read electronically, and can therefore be used to provide kW demand by half hour. Type 5 meters, which record consumption every half hour but need to be manually read, are designed for customers using less than 160 MWh per year. Most domestic customers are on Type 6 metres (using less than 100 MWh per year) which records only total energy consumption and accumulates the data over a billing period.

5.2.2 Complexity and cost

Aside from the technical difficulties of linking customer demand, power flows and system performance, extensive information and analysis is required to develop prices that more accurately represent the cost of network use. This is one reason that DNSPs elect to use highly aggregated tariffs, in which network costs are averaged over a small number of broad customer classes. As the complexity of pricing structures increases so will the cost of administration and billing.

It is apparent that the development and administration of more efficient prices would increase some costs for DNSPs and, to a lesser extent, retailers. These costs would be passed on to customers. However, they would need to be compared with the benefits arising from the avoided costs of inefficient network and consumer investment that might otherwise have gone ahead.[18]

5.2.3 Price Signalling

In principle, it should be possible to combine sophisticated metering with 'real time' pricing – that is, pricing that varies depending on actual network congestion or market conditions.

For a real time price signal to be effective it must be received in a form that the customer, retailer or energy service company can make use of. Communication links that relay notification of price changes may lead to the installation of warning devices or, where appropriate, to automatic demand responses. These may be activated through price sensitive control equipment, or come built in to the energy-using appliance.

However, the introduction of advanced communication and price signalling will be influenced by a number of practical considerations, including:

1. the extent to which customers themselves wish to see and respond to such signals
2. the benefit-cost trade-off in the introduction of such communication, and
3. the complex question of which entity controls the real time price signals – the DNSP in response to network congestion or the retailer in response to wholesale market conditions.

At present, the benefit-cost trade-off for households is probably marginal, although it may improve over time. There may, however, be a role for the retailer or energy service company to co-ordinate and manage the demand response of smaller customers to network prices. Larger customers with sophisticated metering, already have the ability to respond to better targeted price signals.

Over time, the availability of communication and control systems is likely to play a key role in the emergence of broadly based demand side responses. This raises the question of whether the development of effective systems is supported, where necessary, by industry protocols governing communication equipment and the interface with energy-using appliances, should be an area of particular focus for policy-makers and regulators.

5.3 Revenue recovery

A key function of network prices is the recovery of allowed revenues. In large, part a DNSP's revenue requirement is made up of the fixed capital costs of previous investments in network assets – so-called sunk costs. Sunk costs are not affected by current and future consumption decisions. Therefore, from an economic perspective, sunk costs do not provide a basis for signalling the costs of network use. The relevant costs for this purpose are marginal (forward looking) costs.

18 According to EnergyAustralia the difference in costs between providing energy at the peak and energy in the base load period is somewhere in the range of 30 to 40 times. This differential provides a primary opportunity for undertaking DM (Mr Mervyn Davies, General Manager Network, EnergyAustralia – IPART Public Hearing on Demand Management, 20 September 2001). Mr Davies' charts from this presentation are at Attachment 4.

When there is spare capacity, network marginal costs, and hence efficient usage prices, will be low. As capacity is more fully used efficient usage prices will increase towards LRMC. However, only in rare cases will these fully recover allowed (or required) revenues. This leaves a residual revenue requirement that must be recovered by other means.

From an economic perspective residual revenues should be recovered in a manner that has least impact on the current and future level of network use. Thus, residual revenues should be recovered through price elements that, as far as possible, do not influence consumption decisions made by customers.

5.3.1 Fixed and variable charges

In the first instance charges that are fixed with respect to network use come closest to meeting this requirement. Efficient network prices will therefore typically contain a usage-based component and a fixed component.

This raises two issues. When there is spare capacity, efficient pricing suggests that the burden of revenue raising should fall predominantly on the fixed component. However, fixed charges are unpopular with customers and are considered by many as inequitable. This limits their acceptability.

Secondly, the variability in pricing that is introduced by linking usage charges to capacity levels adds to the complexity of aggregate revenue regulation. DNSPs in NSW are subject to a revenue cap and, for residential customers, side constraints. In Victoria a price cap applies. DNSPs may be subject to penalties if these caps and constraints are breached. The introduction of greater variability in pricing structures to meet efficiency objectives will add to the risk of such a breach.

5.3.2 Ramsey pricing

A second option for recovering residual revenues while minimising the effect on network use is the application of so-called Ramsey prices. This is a pricing approach that weights the allocation of residual (non-marginal) costs to customers inversely to their price responsiveness (demand elasticity). The principle is that, because customers with inelastic demands will have a low demand response to a higher weighting of costs, this method will minimise the impact that the recovery of residual revenues will have on efficient consumption levels.

Ramsey pricing is a controversial area of economics because it supports discrimination between customers based on the nature of their demand rather than the costs they impose. Many would regard this as inequitable.

5.4 Price stability

Efficient usage prices by their nature discriminate between customers according to the costs they impose on the network. When capacity is tight, efficient prices will provide incentives for customers to reduce their demand on the network. This will penalise customers with less demand flexibility at peak times. When there is spare capacity and usage prices are low, relatively greater amounts of revenue will be recovered through fixed and other charges.

If customers, because of past equipment investments or other constraints, have very limited ability to adjust their demand at times of system peak, then the introduction of more variable usage charges may seem harsh. In effect the introduction of greater pricing efficiency will increase the price risk for some customers. Over time this may lead to retailers offering supply packages through the competitive retail market that reduce the level of risk. The provision of risk management services through a competitive market is compatible with economic efficiency. However, in the short term there may be a need to manage adjustment costs more directly.

5.5 External costs and benefits

A question that frequently arises when considering the role of prices is the extent to which they reflect all the costs involved. Network poles and wires for example impose a visual and environmental cost on the amenity of the landscape. Some parties argue that there may also be health costs associated with exposure to electro-magnetic fields present around higher voltage lines. These are not easy issues to resolve. Aside from the need to firstly confirm the nature of the impact and, secondly, determine a basis for valuing it, there is the added difficulty of ensuring comparability in the method used to price competing energy service options.

Electricity generation is the main source of externalities associated with electricity production and use. These are most appropriately priced in the energy market. Where this doesn't happen, we can ask whether it is a valid second best solution to include the costs of generation externalities within the distribution network charge. This would have the effect of lifting network charges, and would raise the question of how any resulting increase in DNSP revenues should be treated.

5.6 Equity and customer impacts

The customer impacts of providing pricing signals which reflect true marginal costs according to location and time of day may be quite significant. The efficient network charge to one customer may be considerably higher for a kW of delivered power than for another, simply because coincident maximum demand causes congestion on the network elements supplying the first customer, but not on that supplying the second.

In practice, DNSPs are required to consider customer impacts and equity issues as well as economic efficiency and environmental objectives. In designing the structure of network tariffs, a balance must be struck between providing prices which signal actual network costs at a certain time and place, and meeting reasonable standards of fairness and equity. This is a difficult issue for regulators and service providers to resolve. One approach to reconciling these objectives is to avoid sudden changes in prices by signalling well in advance areas of emerging congestion and phasing in price changes. Another approach would be to make greater use of optional tariffs.[19] A further alternative is to use targeted rebates for reductions in energy use and maximum loads.

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[19] Similar to the case of mobile phone tariff plans, a retailer or energy service provider could offer customers a menu of different tariffs. These tariffs would offer a range of incentives and options, depending on their energy supply needs. Those customers who are able to shift loads away from peak periods will choose a tariff that provides greater gains from such behaviour. However, widespread uptake of such tariffs could lead to an increase in the average base tariffs, for those customers who are not able to shift their demand.

5.7 Current pricing practices

Reflecting the relatively recent emergence of separate network service providers within the electricity industry, the practice of distribution network pricing has a short history in NSW. During this time DNSPs have been required to provide a transition from pre-NEM implied network charges, develop new price structures and in some cases consolidate price lists as their service territories have been altered by government. Current pricing practice reflects, to a certain extent, this relatively short history, as well as the effect of the considerable practical limitations that have been discussed above.

A representative survey of network prices is beyond the scope of this paper. It is helpful, however, to summarise the main features of the current prices set by DNSPs.

Customer class averaging

Generally a high level of averaging is employed. Four broad customer classes – domestic, low voltage, high voltage and sub-transmission – are used. Low voltage and high voltage customer classes are also sub-divided into energy, time-of-use (TOU) and demand tariff categories.

Demand measures

At LV and above most, though not all, NSW DNSPs offer customers with compliant metering a tariff that includes a TOU demand component. Pre-set peak/shoulder and off-peak periods are used. Demand is measured on a kVA basis where metering permits, otherwise kW is used. Maximum demand is recorded on a monthly basis and charges are based on either monthly or annual resets.

Seasonal measures

These are not currently used. EnergyAustralia is considering the introduction of a seasonal component to its prices in 2002.

Locational measures

Except for the variations in Country Energy's pricing zones reflecting the former constituent networks, no locational signals are present in current tariffs for other than very large customers (charges are individually set for customers with loads greater than 10MW).

Interruptible and controlled loads

All DNSPs offer controlled supply to domestic water and space heating appliances. In 2001 EnergyAustralia introduced an interruptible load tariff for LV customers.

Congestion pricing

Demand charges or rebates that vary with the level of network congestion are not available in NSW.

The NSW DNSPs have been concerned about worsening load factors and power factors for some time and have been exploring possible pricing responses, such as greater reliance on demand charges, within the existing constraints on pricing. The growth in residential air conditioning in recent years, particularly in EnergyAustralia and Integral's areas has exacerbated these difficulties. In response to this EnergyAustralia have:

- Introduced an interruptible option for the LV Energy 40 network tariff available to customers with an annual consumption less than 40 MWh pa. In return for a 25 per cent discount on the peak and shoulder rates, customers allow EA to interrupt supply to fixed wired appliances on this tariff.
- Proposed to extend the use of the LV Energy 40 time-of-use tariff to other larger customers and make it mandatory for residential customers installing three phase air conditioners. The interruptible option would also be available for these customers.
- Proposed to increase the differences between prices for peak and off-peak periods for customers on time-of-use tariffs and alter the peak period to include summer afternoons when air conditioning may lead to network constraints.
- Proposed to introduce price incentives for large customers to improve their load factors.
- Proposed to progressively increase the capacity charge for business customers to provide incentives for these customers to alter their usage patterns.
- Proposed to monitor those parts of the network needing augmentation and trial options for seasonal or geographic components of prices.

Further details are available in EnergyAustralia's 2001 Price and Service Report (available at www.energy.com.au/ea/earetail.nsf/Content/NetworkDistributionPricing_OurNetwork). Many of these initiatives are yet to be implemented so their effectiveness cannot be determined at this stage. However, NZ experience suggests that innovative pricing that is integrated with network planning and corporate strategies can be effective.

5.8 Case study – congestion pricing in New Zealand

In New Zealand concerns over the cost of system augmentations at both the distribution and transmission levels have created considerable interest in the cost signalling role of network charges. For some years now two South Island distributors, Dunedin Electricity and Orion New Zealand,[20] have used a form of congestion pricing to signal the cost of network demand constraints. This approach involves:

- a separate congestion period charge is applied at times when demand on the network (coincident demand) is high
- the charge is based on the long run incremental cost of those network elements sized to meet coincident system demand; separate congestion charges are applied to distribution and transmission network use
- the charges apply to electricity used during declared congestion periods[21] when demand on the network reaches levels at which the distributor is required to control load;[22] the timing and duration of the congestion periods is determined by the level of coincident demand,[23] allowing real time demand responses from customers
- information provision and market activation programs are used to support the price signal; customers and retailers are provided with regular updates on the likelihood of congestion conditions emerging; notice of an impending congestion period is provided through a range of media
- for customers with compliant metering a ripple control signal[24] is sent out; in combination with the advance notice of a congestion period provided by the distributor, this allows demand responses, either automated or manual, to be triggered
- congestion periods only apply during the months of peak demand; network areas are designated as either winter peaking or summer peaking.

Both Dunedin and Orion use the congestion charge in combination with fixed charges and capacity charges.[25] The congestion charges are significant. Currently Orion recovers approximately 45 per cent of its distribution network revenue from this source.

The level of charge varies. Orion currently applies a uniform distribution congestion charge of NZ$60/kVA/year for direct (major) customers and NZ$85/kVA/year for retailers.[26] Transmission congestion charges are NZ$21.92 and NZ$35/kVA/year respectively. Dunedin applies a declining block structure to its congestion charges, with distribution charges ranging from approximately NZ$30 to NZ$80/kW/year and transmission charges averaging around NZ$55/kW/year.

20 Further information is available on their websites, www.oriongroup.co.nz and www.electricity.co.nz
21 Orion calls these 'Control Periods'.
22 For example, domestic hot water storage units that can be turned on or off by a signal from the distributor.
23 Coincident demand is the total demand placed on the network at any one time.
24 Ripple control signals are used by the distributor to operate controllable loads, such as hot water storage units.
25 The capacity charges are equivalent in form to the demand charges applied by NSW DNSPs. They are used to reflect the cost to the network of meeting the diversity in customer demands.
26 Orion leaves it up to the retailer to decide whether or not to pass through the congestion charge to the end use customer.

The charge is applied to the average congestion period demand recorded over the peak season.[27] The accumulated duration of the congestion periods over a season will vary according to weather and other conditions. The congestion period is likely to occur on cold winter days, anytime between 7.30 am and 9.30 pm and to last for one to three hours (but longer on occasions). Orion estimate that in an average year there will be around 60 congestion period hours. On this basis a major customer of Orion would face (or avoid) a combined distribution and transmission charge equivalent to NZ$1.37 for each kVA hour taken (or not taken) during a congestion period.[28] This is a significant price signal. As Dunedin comment in their pricing statement:

> By signalling demand constraints in this way, Dunedin Electricity is able to defer the need for investment in more capacity which is a very expensive alternative. Load is controlled only when the network loading is approaching the network's capacity. Consumers do not have to respond every time the signal is sent. Many will respond only when it suits, however the rewards for responding are substantial.

Since introducing congestion period pricing in the mid-1990s, Orion has recorded minimal growth in system peak demand. Consequently its customers have been spared the expense of peak driven additions to distribution and transmission network capacity. Interestingly these pricing approaches have been developed by the distributors without the need for any regulatory prompting.

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27 Given by taking total energy consumed over the congestion periods and dividing by the number of hours. A two-stage monthly billing process is used. Preliminary bills are based on the previous year's pattern of demand. Once final figures are known at the end of the peak season a reconciliation and make-up adjustment is applied.

28 Orion's combined congestion period charge for major customers is NZ$81.92/kVA/year ($60 for distribution and $21.92 for transmission). If there are 60 congestion period hours in a year the equivalent hourly charge is NZ$1.37.

6 ROLE OF THE REGULATOR

In the absence of a market capable of producing efficient distribution network prices what, if anything, should regulators do to support their development?

Distribution networks are subject to economic regulation because of the dominant role of DNSPs in the delivery of electricity. There is broad recognition and acceptance of the need for limits to be placed on the ability of DNSPs to exploit their dominant position. How this should be done is subject to vigorous debate.

Within the NEM the primary form of economic regulation is applied through aggregate revenue or price caps. Scope is also provided for jurisdictional regulators to determine the principles and methods to be used in setting network prices. The Tribunal has taken this opportunity and developed pricing principles (the PPM[29]) to guide the setting of network charges by DNSPs in NSW.

6.1 PPM

The PPM, which took effect from 1 July 2001, represents a significant development in the level of regulatory interest in the pricing behaviour of DNSPs. The decision to issue the PPM stemmed in part from concerns with the pricing sections of the Code.[30] Primarily, however, it reflects the Tribunal's view of the central role played by network prices in promoting economic use of the network and efficient investment in network development, DM options and distributed generation.

The PPM detail a comprehensive set of principles[31] that DNSPs are required to apply in the pricing of network services. The importance of signalling economic costs is specifically recognised in principles 4 to 7:[32]

> 4. Prices are to signal the economic costs of service provision, by:
>   a) being subsidy free (greater than incremental costs and less than stand alone costs)
>   b) having regard to the level of available service capacity, and
>   c) signalling the impact of additional usage on future investment costs.
>
> 5. Where prices based on 'efficient' incremental costs under-recover allowed revenues, the shortfall should be made up in a manner that minimises the effect on consumption and investment while having regard to the impact on users, and should:
>   a) not vary between locations
>   b) contain a fixed component; and
>   c) to the extent a variable component is necessary and metering permits, include both energy and demand components. Where metering permits their use and

29 IPART, *Regulation of New South Wales Electricity Distribution Networks, Pricing Principles and Methodologies for Prescribed Electricity Distribution Services, Developed pursuant to clause 6.11(e) of Part E, Chapter 6 of the Code*, March 2001.

30 specifically Part E of chapter 6 of the National Electricity Code.

31 The pricing principles are listed in full in Attachment 1.

32 *Regulation of New South Wales Electricity Distribution Networks, Pricing Principles and Methodologies for Prescribed Electricity Distribution Services, Developed pursuant to clause 6.11(e) of Part E, Chapter 6 of the Code*, March 2001, Schedule 1, p 20.

user impacts are manageable, costs recovered through demand or time of use pricing components should not exceed the long run marginal cost of supply.

6. Provided that economic costs are covered, prices should be responsive to the requirements and circumstances of users in order to:
   a) discourage uneconomic bypass, and
   b) allow negotiation to better reflect the economic value of specific services, including services associated with embedded generation and other options.

7. When allocating TUOS charges to distribution network users distributors should, where practicable, preserve the economic signals present in the structure of TUOS charges. Information on allocated TUOS charges should be available to users on request, where practicable.

The approach taken in the PPM is based on three key propositions concerning the role of price regulation:

- DNSPs should be responsible for determining their prices, given that they have a better understanding of their cost structures, the needs of customers and their sensitivity to price signals, the level of network utilisation and the likelihood of the emergence of congestion
- pricing involves judgement and the balancing of objectives; it is not amenable to simple rules; therefore, regulation will be applied primarily through the use of qualitative rather than quantitative criteria
- pricing behaviour will most effectively be influenced by a regime of information disclosure and open critical review; however, a formal price compliance review does apply each year.

In essence this reflects a view that, notwithstanding the importance of network prices, there are limits on the effectiveness and desirability of direct price regulation.

Information provision, reporting and consultation play an important role in the PPM. DNSPs are required to publish annual Price and Service Reports in which, *inter alia*, they explain their pricing method and rationale, provide data on the cost basis and explain the extent to which their prices incorporate the PPM's pricing principles.[33] In particular, DNSPs are required to respond to questions specifically directed at the marginal cost signals provided in their prices:[34]

> Do prices reflect the future need for augmentation of the network? Prices may be expected to be higher in locations where the system is closer to capacity. DNSPs should report on the significance of locational congestion and related capex requirements across their network. DNSPs should explain their decision to use or avoid locational price signals in the context of the congestion costs they face.
>
> Does the structure of prices reflect marginal economic costs? DNSPs should explain the extent to which prices signal marginal costs and the basis for their decisions on the weights applied to the fixed and variable price components.

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33 Attachment 2 lists the PPM information requirements.

34 IPART, *Regulation of New South Wales Electricity Distribution Networks, Pricing Principles and Methodologies for Prescribed Electricity Distribution Services, Developed pursuant to clause 6.11(e) of Part E, Chapter 6 of the Code*, March 2001, Schedule 3, para 3, p 23.

The Tribunal reviews the information provided by DNSPs and any feedback it has received from other parties, then publishes a summary and commentary on the DNSPs' pricing practices and price outcomes. The approach is flexible – if considered necessary the Tribunal will amend either or all of the principles, reporting requirements and price compliance criteria.

6.2 Further options

Further regulatory options can be divided into two broad streams according to the degree of prescription involved.

6.2.1 Extending the current non-prescriptive approach

The current PPM takes a non-prescriptive approach. Within this framework there are opportunities to place greater weight on the objective of efficient network use and investment. For example the Tribunal could:

- provide guidance on the relative weights to apply to the various pricing objectives in the PPM
- upgrade the references to congestion price signalling in the pricing principles and DNSP reporting requirements (Attachment 3 contains proposed amendments to Schedule 3 of the PPM). In response to this, DNSPs could be encouraged to at least establish trials of congestion and locational pricing options:
    - one proposal in regard to congestion signalling is the concept of a rebate[35] whereby customers or retailers receive signals that capacity constraints are occurring on the system and are offered the incentive of a rebate in network charges if demand is reduced. This would require more sophisticated communication between network asset management systems, retail energy trading systems and customer energy management systems
- introduce specific pricing measures to the list of matters that DNSPs are required to address in their Price and Service Reports, such as:
    - the use of distribution price regions or regional price factors to allow some locational signals, including the preservation of locational transmission price signals
    - the use of NZ-style congestion price periods
    - the use of price rebates for demand reductions at times of network congestion
    - greater use of interruptible load pricing and seasonal price signals
- formally require DNSPs to assess the efficiency of their prices and propose options that would improve the signals for efficient investment in network development, DM options and distributed generation.

Reference has been made earlier to the tensions that can exist between regulatory objectives or measures. Part of any decision by the regulator to increase the weight given to efficient pricing should be a clarification of priorities – for example the reasonable limits for customer impacts and variations in price or revenue cap outcomes.

35 Srian Abeysuriya, Sigma Utility Solutions Pty Ltd – presentation to IPART Secretariat, 15 October 2001.

6.2.2 Introducing a more prescriptive approach

An alternative is to more directly specify the structure of network charges. For example, subject to metering availability, DNSPs could be required to include one or more of the following components in their charges:

- TOU demand (kVA where possible)
- seasonal demand
- a locational factor to reflect local constraints and/or locational transmission price signals
- congestion-related demand.

DNSPs could also be required to develop trials of congestion pricing approaches, for example focusing on areas that are expected to become congested over the next 3 to 5 years.

Prescription could also be extended to the range of service offered – all DNSPs could be required to offer an interruptible service option for example – or to the costs recovered through prices – specified environmental costs for example.

7 CONCLUSIONS AND A WAY FORWARD

Demand management and related options form a potentially significant but largely undeveloped part of the energy services market. Just how significant is one of the questions to be addressed by the current review.

This paper has considered the role of network pricing in the development of the energy services market. There are five broad conclusions:

- distribution networks are part of the energy services market, and should be treated as such
- as in any market, pricing has a critical influence on bringing forward the least cost combination of supply and demand responses; distribution network pricing is no exception
- pricing should form an integral part of DNSP network planning and investment
- efficient pricing is a useful concept, but to be practical priorities must be set
- while regulation can help set those priorities, the value of more prescriptive price control is questionable.

7.1 Distribution networks are part of the energy services market

Electricity markets are continuing to develop. Options for the closer integration of transmission services within the wholesale power market are receiving close attention. Transmission pricing is being moved closer to a form that is more consistent with market-based signals. At the retail end the move to full competition is proceeding.

There is no basis for quarantining distribution networks from this process. On the contrary, distribution networks are a vital link in the development of the energy services market. All of the main sources of competition to large-scale remote generation (ie base load coal-fired generation), transmission and distribution networks – distributed generation, cogeneration, demand-side bids and other demand management options – have their economics influenced by the performance and the pricing of distribution network services.

As the examples of the New Zealand distributors Orion and Dunedin have shown, congestion pricing can be a useful and effective tool for deferring the need for costly investment in additional network capacity.

7.2 Pricing is a key issue

While there are a number of ways in which market-based processes can be extended to the distribution sector, the use of prices that more clearly signal the economic costs of network use is a key issue. This may include, for example, more effective capacity signalling by time-of-use and location and the preservation of transmission use of system (TUOS) economic price signals. Poor price signals lead to wasteful investments and increased costs for customers.

Pricing should be seen as critical part of a wider market development program for energy services. Other important elements include more open network planning (now incorporated into the DM Code) and encouraging price responsive behaviour. Access to effective communication and load control systems is a key influence on price responsiveness.

7.3 Pricing and network planning

The principle of efficient pricing needs to be integrated within the corporate strategy of the network service provider so that it becomes an integral component of its approach to network planning and investment. The interrelationship between current pricing signals, efficient utilisation of the network and future investment requirements must be recognised by DNSPs.

7.4 Pricing in practice – the need to set priorities

Efficient pricing is a useful concept but it can do no more than act as a guide. In practice pricing decisions are made against a background of incomplete information and multiple, sometimes conflicting objectives. Regulators can help by clearly setting out their priorities for pricing, particularly where there is tension between regulatory objectives.

The initial focus for DNSPs should be those areas where price responsiveness is likely to be most significant or the practical constraints less binding – larger customers or regions subject to an immediate or imminent constraint, for example.

Policy-makers and regulators can help by clearly setting out their priorities for pricing and by applying a coordinated and consistent approach across the industry. Metering, communications and appliance control systems in particular are areas that will significantly impact the development of demand side responses.

7.5 Price regulation

Pricing is a basic commercial activity for any business. DNSPs are established as independent commercial entities, with requirements to operate efficiently and profitably. Currently, economic regulation is based on the use of incentives rather than prescription.

With the introduction of the PPM the Tribunal has stepped up its involvement in the price setting process. The PPM establish pricing principles and aim to influence pricing behaviour indirectly through exposing pricing practices to public scrutiny and critical review. However, a basic premise of the PPM is that DNSPs should have responsibility for setting their prices.

7.6 A way forward

A move to more efficient distribution network pricing is recommended as one element of a program to develop an effective energy services market. The PPM already provide the Tribunal with a robust regulatory framework; price efficiency is specifically addressed in both the pricing principles and information requirements. At this stage there appear to be no grounds for suggesting that either the principles or the information requirements need significant amendment.

The non-prescriptive approach taken in the PPM is supported. The PPM are relatively new and more time should be allowed to judge their performance before considering the introduction of greater prescription.

In conjunction with other market development and pro-competitive measures – such as the recently upgraded emphasis in the DM Code of Practice on more open network planning and investment decisions – it is recommended that the Tribunal:

1. support the proposition that distribution network service provision should be subject to the same progressive introduction of market-based principles and processes as other sectors within the industry and incorporate this position into its future regulatory actions
2. emphasise the role of distribution network pricing in supporting efficient wholesale and retail markets and minimising the economic costs of energy service, including DM and distributed generation, by:
   (a) upgrading the references to economic cost signals in the PPM (Attachment 3 contains proposed amendments to Schedule 3 of the PPM); the PPM framework could be used to encourage DNSPs to trial congestion period and locational pricing options
   (b) strictly implementing the reporting and information requirements of the PPM
   (c) using IPART's annual review of price and service to provide a comprehensive and critical assessment of the efficiency of DNSP prices and their contribution to efficient network use and investment and the development of the energy services market
   (d) including in this assessment peer group comparisons from other states and overseas and, where appropriate, commissioning research on network pricing, and as a consequence
   (e) actively engaging the DNSPs in a process directed at developing more efficient or market-based pricing.

ATTACHMENT 1 CURRENT DISTRIBUTION NETWORK PRICING PRINCIPLES

The pricing principles set out in the current PPM (March 2001, Schedule 1) are as follows. The intervening comments are taken from the explanatory report accompanying the PPM.

1. Prices are to be consistent with the regulated revenue or price cap and any applicable side constraints determined by the Tribunal.

A primary function of prices is the recovery of regulated revenues. The revenue cap set by the Tribunal allows for financial viability where operations meet reasonable efficiency targets. For equity reasons the Tribunal also limits the annual change in some prices.

2. Prices should be based on a well-defined and clearly explained methodology.

Where there is substantial market power, open and transparent pricing practices are essential.

3. Price development should incorporate an analysis of the cost of service provision that includes:

- ***a) definition of the classes of service provided and the parameters by which the quantum and standard of service in each class are measured***
- ***b) an examination of the cost elements that arise from the use, operation and expansion of the network***
- ***c) for each class of service and each cost element, identification of the relationship between the quantum and standard of service provided and the level of current and future cost***
- ***d) an allocation of existing and future network costs to service classes***
- ***e) the translation of allocated costs into service prices at the defined service standard, and***
- ***f) estimates of the range of subsidy-free prices for each service class.***

The measurement and allocation of costs form the basic building blocks of price development. A range of feasible approaches exist. However, for distributors to be able to demonstrate that their prices are soundly based, efficient and transparent, the process of price development must be rigorous and systematic.

4. Prices are to signal the economic costs of service provision, by:

- ***a) being subsidy free (greater than incremental costs and less than stand alone costs)***
- ***b) having regard to the level of available service capacity, and***
- ***c) signalling the impact of additional usage on future investment costs.***

Prices can influence how customers use the distribution network and how distributors operate and maintain it. They can also influence the level of investment undertaken in expanding capacity. Where prices reflect the economic value of the resources used in providing a service, they make an important contribution to economic efficiency and welfare.

Economic efficiency requires that prices give correct signals for the use, operation and expansion of the network. This encompasses both allocative and dynamic efficiency. These objectives share a common starting point: the efficient, forward-looking costs of meeting additional network loads.

There is considerable debate over the measurement of the upper and lower bounds for the range of subsidy-free prices (ie stand alone cost and incremental cost). The PPM does not mandate a particular methodology. Rather, it allows distributors to select the approach they consider most appropriate to their circumstances.

Congestion signalling is typically difficult to implement and administer. Sophisticated price signalling will be subject to metering constraints. Signals may be provided through price levels or price structure. In some circumstances, varying the price structure without changing the revenue raised may form a more practical alternative.

5. ***Where prices based on 'efficient' incremental costs under-recover allowed revenues, the shortfall should be made up in a manner that minimises the effect on consumption and investment while having regard to the impact on users, and should:***
   a) ***not vary between locations***
   b) ***contain a fixed component; and***
   c) ***to the extent a variable component is necessary and metering permits, include both energy and demand components. Where metering permits their use and user impacts are manageable, costs recovered through demand or time of use pricing components should not exceed the long run marginal cost of supply.***

Economic efficiency requires that usage prices recover at least avoidable costs. This can lead to a shortfall in revenue, since for most networks avoidable costs are less than average costs for most of the time. In considering revenue make-up options, minimising the impacts on consumption and investment decisions are important criteria.

6. ***Provided that economic costs are covered, prices should be responsive to the requirements and circumstances of users in order to:***
   a) ***discourage uneconomic bypass, and***
   b) ***allow negotiation to better reflect the economic value of specific services, including services associated with embedded generation and other options.***

Users may have individual service requirements that vary from the standard form offered. To maximise the economic benefits available from use of the network, an approach to pricing that is responsive to user requirements and circumstances will be required.

7. ***When allocating TUOS charges to distribution network users distributors should, where practicable, preserve the economic signals present in the structure of TUOS charges. Information on allocated TUOS charges should be available to users on request, where practicable.***

Distribution network charges include an allowance for charges paid by distributors for use of the transmission system (known as TUOS charges). Distributors should have regard to the economic signals present in the structure of TUOS charges when determining the basis for allocating the charges across users of the distribution network.

Users may have an interest in knowing the extent of their contribution to the distributor's TUOS charges. Availability of this price information may lead to more efficient consumption and investment decisions. Metering constraints on the availability of data and the level of charges applied to meet the additional cost of providing the information are matters that would need to be addressed.

8. Information on customer class price levels and structures, service standards, underlying costs, price derivation methods and rationale and medium term price and service strategies should be publicly disclosed in order to allow:

- ***a) current and potential users to understand the basis for prices and to take account of prices and service standards in their consumption, investment and location decisions***
- ***b) interested parties to better assess the range of opportunities for meeting user requirements, including through services associated with embedded generation, demand management and other options that may reduce users' costs and lead to more efficient outcomes.***

Access to information is a key factor affecting market efficiency. The availability and transparency of price information is an essential ingredient for sound decision making. Since investment decisions rely on expectations about the future, this applies equally to information on future prices and service levels.

Some network services are potentially open to competition in meeting users' requirements. Where alternative or competing forms of service provision may be available, users should have the opportunity to choose the option with the lowest economic cost.

9. Underlying service classifications, cost data, cost allocations and other elements that contribute to pricing decisions should be periodically reviewed and updated where relevant to reflect industry developments and changes in user requirements and preferences, methods of service provision and costs.

Changes in areas such as metering technology, retail competition, alternative forms of service provision and user preferences can lead to shifts in the nature of efficient network prices. For prices to remain efficient they should reflect such developments.

10. Where distributor price strategies lead to proposed price movements or price restructuring that may be expected to impose significant adjustment costs on users, transitional price options, a phased approach or other measures should be offered to assist in the management of adjustment costs.

End-users make decisions on location, production and investment in electricity-consuming equipment that are influenced by existing prices. Thus substantial or frequent price changes can impose unreasonable or inequitable adjustment costs on them. Such pricing practices can also reduce economic efficiency by increasing the level of uncertainty and risk.

ATTACHMENT 2 PPM INFORMATION DISCLOSURE REQUIREMENTS (MARCH 2001, SCHEDULE 3)

1. A DNSP's Price and Service Report will provide information on customer class price levels and structures, service standards, underlying costs, price derivation methods and rationale and medium term price and service strategies in order to allow:
   a) current and potential users to understand the basis for prices and to take account of prices and service standards in their consumption, investment and location decisions
   b) interested parties to better assess the range of economic opportunities for meeting user requirements, including through services associated with embedded generation, demand management and other options that may reduce users' costs and lead to more efficient outcomes.
2. A DNSP's Price and Service Report will clearly document, describe and explain:
   a) the level and structure of prices
   b) the standard of service provided
   c) the methodology used to derive prices and their cost basis, and
   d) medium term directions for prices and standards of service.
3. DNSPs are required to address the following broad questions in their Price and Service Reports.
   a) Are the prices subsidy free? The test for this is whether the prices for individual customers are between the stand-alone and incremental costs of supply. DNSPs must demonstrate that prices lie within this range and explain how they determine the range.
   b) Do prices have regard to an acceptable cost of supply model? The cost modelling referred to in the development of the Proposed Prices should be disclosed. This should include an explanation of the basis for the allocation of TUOS charges to distribution network prices.
   c) Do prices reflect the future need for augmentation of the network? Prices may be expected to be higher in locations where the system is closer to capacity. DNSPs should report on the significance of locational congestion and related capex requirements across their network. DNSPs should explain their decision to use or avoid locational price signals in the context of the congestion costs they face.
   d) Does the structure of prices reflect marginal economic costs? DNSPs should explain the extent to which prices signal marginal costs and the basis for their decisions on the weights applied to the fixed and variable price components.
   e) Are the prices consistent with allowed revenues? DNSPs should report the level of their overs and unders account and explain the means by which they intend to maintain consistency between prices and allowed revenues.
   f) What is the impact of the DNSP's price strategies on price stability in the short term? The impact of price changes introduced for the current year on representative user profiles (to be provided by the Tribunal) should be described and the reasons for the changes explained.

g) What is the impact of the DNSP's price strategies on price stability in the medium term? The DNSP's medium term price strategies and the expected impact on price outcomes for customer classes should be described. DNSPs should indicate whether the strategies are likely to create material adjustment costs for some users and if so the management options available to users and transitional measures that the DNSP may adopt.

h) What level of service performance is provided for the prices charged? DNSPs should report and explain the level of reliability and quality of service they provide to localities across their service areas. Variations in service levels should be explained and expected medium term trends described.

4. In responding to the requirements of paragraphs 2 and 3, the information disclosed must include, but is not limited to:

   a) cost information provided in a form consistent with the Tribunal's pro forma information template

   b) the basis for allocating shared costs

   c) an explanation and quantification of the methodology used to calculate current prices from the costs identified under (a)

   d) unders and overs account balance, tolerance margin and action plan

   e) forecast demand and load factors used in calculating current prices

   f) a summary of asset management and development plans and their relationship to prices

   g) data on performance measured against key service standard indicators; and

   h) an outline of future strategies for pricing and standards of service.

ATTACHMENT 3 PROPOSED AMENDMENTS TO SCHEDULE 3 OF THE PPM

These proposals upgrade the information disclosure requirements on the use of economic cost signals by DNSPs. Paragraph 3 (c) of Schedule 3 is replaced and an additional paragraph 3 (d) inserted.

New paragraph 3 (c):

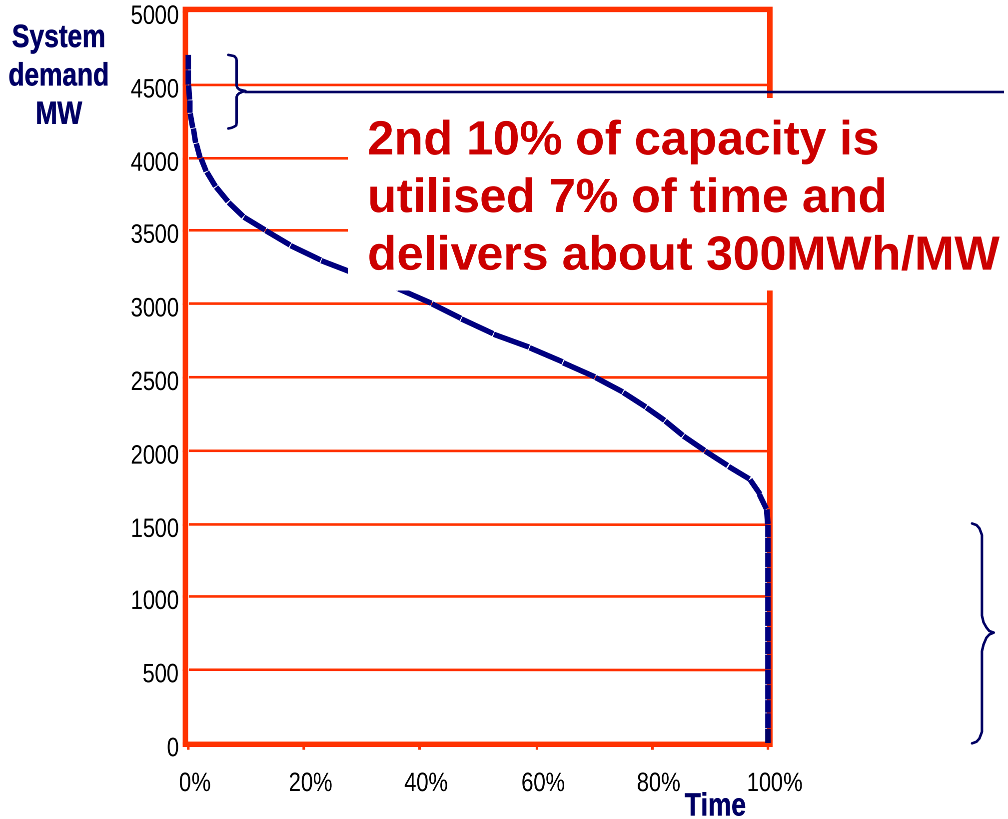
> Do prices reflect the future need for augmentation of the network? Prices may be expected to be higher at times or at locations where the system is closer to capacity. DNSPs should report on the growth of demand, the significance of network congestion (by location where relevant) and related capex requirements across their network. DNSPs should explain their decision to use or avoid congestion price signals, including locational signals, in the context of demand growth and the congestion costs they face.

Additional paragraph 3 (d):

> Do prices preserve the economic signals present in the structure of transmission use of system charges? DNSPs should explain the extent to which transmission price signals, including locational signals, are preserved within their network charges.

ATTACHMENT 4 PRESENTATION BY MR M DAVIES

Pricing signals and Demand Side Response
Load duration curve



Peak Load

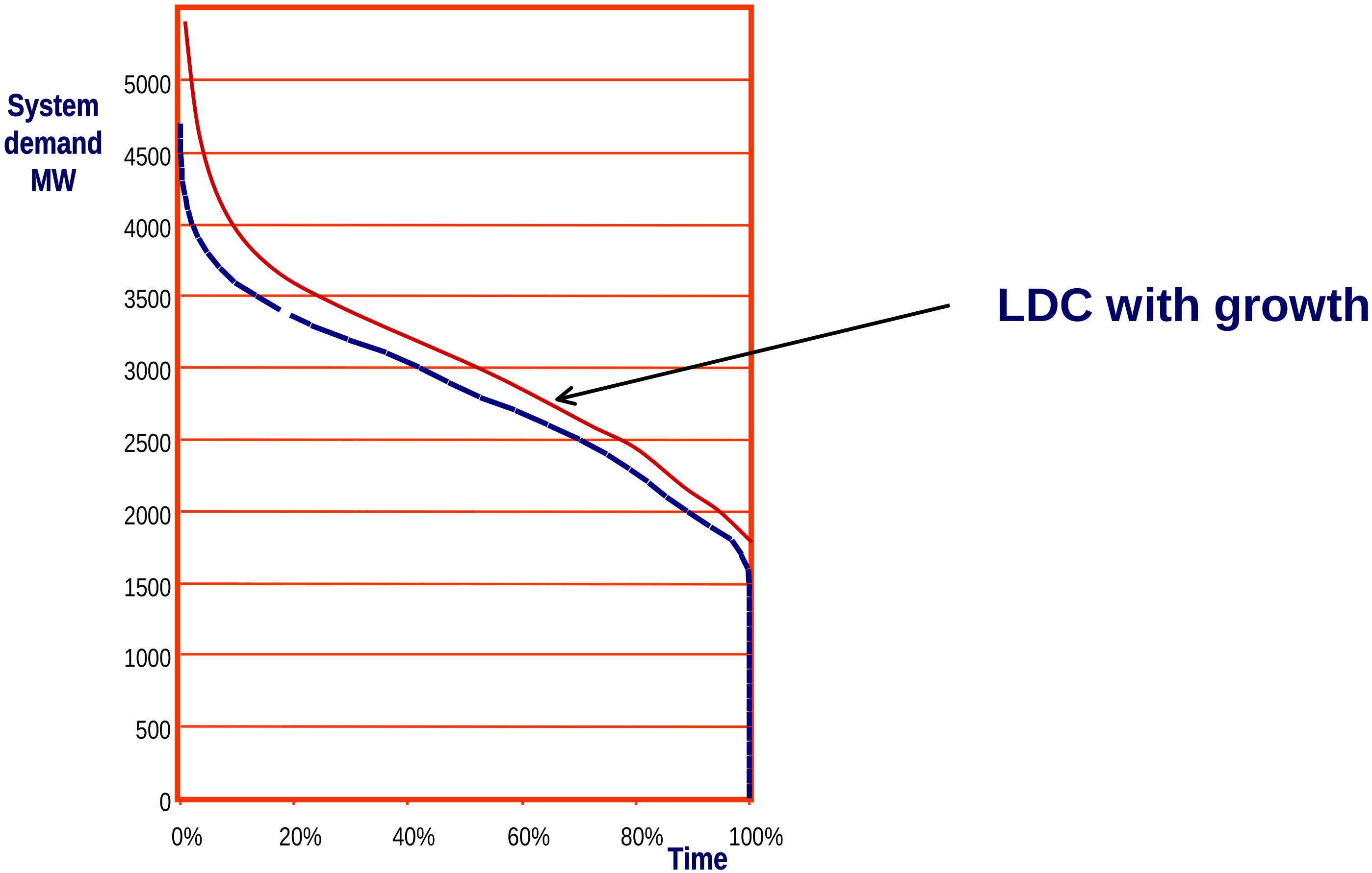
Top 10% of capacity is utilised less than 1% of time and delivers about 20 MWh/MW

Base Load

Bottom 30% of capacity is utilised 100% and delivers 8760 MWh/MW

- **with generation: inexpensive high running cost plant supplies peak load**
  expensive low running cost plant supplies base load
- **in distribution same cost plant supplies both peak and base load**
- **arguably distribution peak load cost is 400 times base load cost**

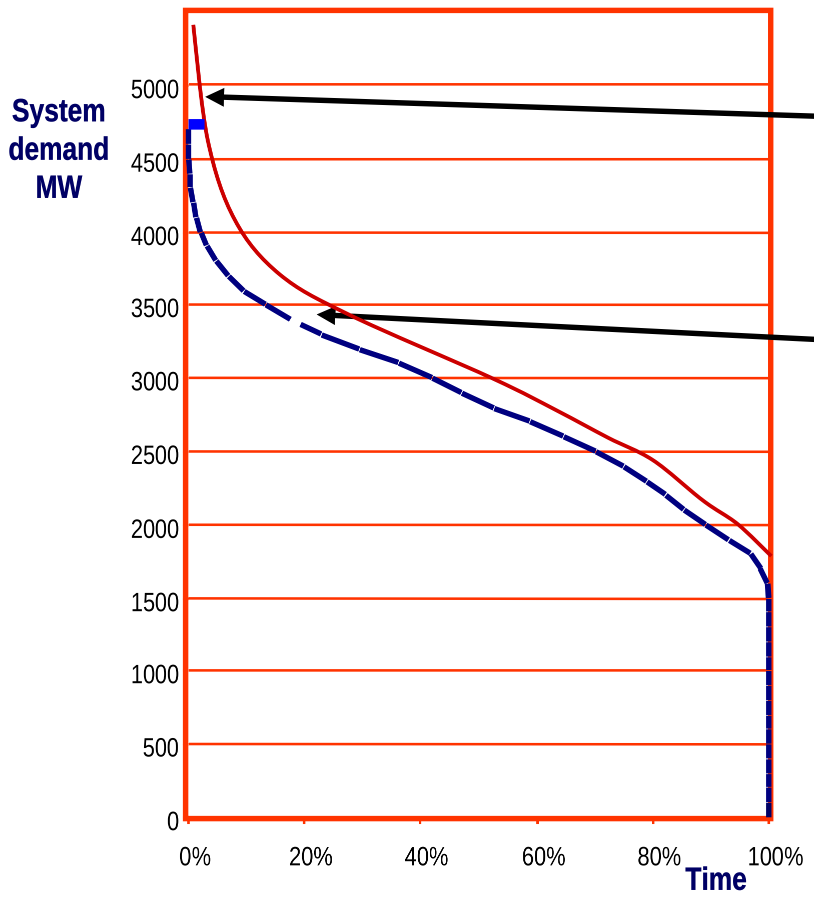
Load Duration Curve with Growth



- Marginal demand delivers 1/400 th kWh of base
- Marginal capacity (investment) is utilised approximately 3% of base
- Marginal cost/kWh 30/40 times base
- Marginal cost/kW is approximately the same

Energy

Load Duration Curve with Growth

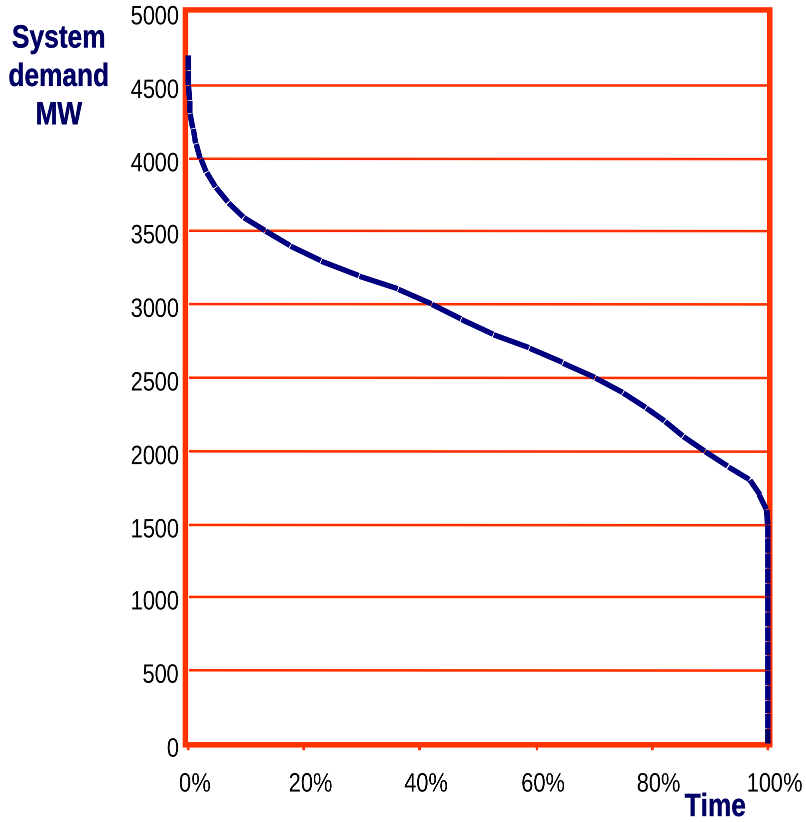


Clipped peak - avoided capacity cost

Improved utilisation of sunk investment

Energy

Pricing signals and Demand Side Response
Load duration curve



Energy