A new approach to congestion pricing in electricity markets: Improving user pays pricing incentives

Author

Nelson, Tim, Orton, Fiona

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1. Introduction

Electricity is relatively unique among goods and services as it cannot be stored economically. As it is produced, it must be consumed. Inventory management cannot be used to allow for smooth production schedules to meet variable demand. Electricity markets are also characterised by significant demand variability as a result of changes in weather. Space heating and cooling requirements can result in rapid increases in demand for small periods on the coolest and hottest days respectively. These characteristics manifest themselves in a low utilisation rate for installed capital. For example, in the Australian National Electricity Market (NEM), total capacity is currently 49,000 MW but annual output is only 205,000MWh (ESAA (2010)). This represents an effective utilisation rate of around 47%. Very few industries with market based pricing have such low utilisation rates of installed capital.

Historically, retail electricity prices around the world have been based upon the total costs of supplying customers averaged across the total energy consumed. Where demand is not variable across time, this 'flat tariff' or 'average cost' approach appropriately allocates costs to users assuming that the cost of providing an additional unit of demand capacity is a linear function. However, this approach breaks down when demand varies according to the time of day. This is because the distribution and transmission network capital costs associated with installing peak levels of *capacity* ($/MW) translate into significantly higher unit *energy* costs (in $/MWh) as the costs are spread across a lower level of consumption. Furthermore, the cost of energy from a peaking power station (e.g. OCGT[1]) is often double that of a baseload power station (e.g. coal) (ACIL Tasman (2010)). A 'flat tariff' approach apportions these underutilised peak capacity costs to all users regardless of whether they actually contribute to the peak demand.

[1] Open-cycle gas turbine

New forms of electricity pricing have been considered as technologies have been developed which allow for more differentiated forms of pricing. In particular, remotely read smart-metering technologies allow energy companies to determine when a user has consumed electricity and differentiate tariffs as a function of time. 'Time of use' (ToU) pricing has been widely documented as a form of congestion pricing in both electricity and transportation markets. While much of the focus in developing new forms of ToU congestion pricing has been on the time point at which congestion occurs, there has been little focus on the other time periods where large amounts of capacity sits idle. The purpose of this paper is to challenge whether tariffs set as a function of time are the most appropriate way of pricing electricity and ensuring that end-users receive the most appropriate pricing signals. We propose that tariffs as a function of both time and individual demand variability (based upon a measure of first derivative rate of change) may be better suited to pricing electricity effectively.

It is timely for discussion to occur about the best way to price electricity. Historically, electricity pricing has not necessarily been a high profile public policy issue. However, many countries around the world are now grappling with much higher electricity prices as a result of two main factors: peak demand growth and lower rates of utilisation of energy infrastructure; and the move towards new sources of fuel (in particular gas and renewables). Peak demand growth is being driven by wealthier communities installing space heating and cooling devices which are used for short periods of time. The capital costs associated with installing higher levels of peak demand capacity are recovered as charges based on actual energy consumed rather than capacity. This focus on energy rather than capacity forms the basis for electricity pricing. The switch to new sources of fuel with higher costs is largely driven by government policy aimed at improving energy security and/or reducing anthropogenic greenhouse gas emissions.

In the Australian context, Simshauser, Nelson and Doan (2011) demonstrated that electricity prices at the household level are likely to double between FY08 and FY15. Importantly, the study concluded that price increases are likely to be driven by higher capital costs, higher fuel costs and significantly greater levels of expenditure on electricity networks as peak demand increases materially. In fact, peak demand in some jurisdictions within Australia is currently growing at double the rate of underlying energy demand resulting in a further deterioration in the capital utilisation rate (AEMO (2010)).

Section 2 of this paper outlines the current approaches to electricity pricing based upon flat tariffs, inclining/declining block tariffs and ToU pricing and proposes a set of assessment criteria by which to compare tariff structure designs. Section 3 presents a simple two-user electricity market and demonstrates that flat tariff and ToU pricing regimes do not adequately allocate costs of building capacity to end users based upon their use of electricity. The macroeconomic costs associated with ToU pricing customer cross-subsidisation are explored in Section 4. Alternative models to ToU and flat tariffs are discussed in Section 5. Specifically, new models of pricing based upon demand variability are proposed. Importantly, simple approximations of our new models of pricing could be implemented with or without smart metering technology. Section 6 contains an assessment of various tariff structures against the nominated criteria, concluding that "first derivative ratio" (FDR) pricing best meets these requirements. Section 7 outlines policy recommendations based upon our findings and provides concluding remarks.

2. Current Approach to Pricing and Criteria for Assessment

Electricity supply chains are essentially composed of three components: wholesale markets (generation of electricity); transmission and distribution (the use of poles and wires); and retailing (billing and customer service). In Australia, the National Electricity Market (NEM) provides a wholesale market for generators and retailers to sell and buy electricity. The NEM uses a uniform, first-price, energy-only gross pool auction design. Accordingly, wholesale electricity prices are effectively ToU prices. The pricing of distribution and transmission is generally based upon flat average cost tariffs regulated by the Australian Energy Regulator (AER). However, some jurisdictions use a combination of fixed (capacity) and variable (usage) charges. Energex (2010) is an example of such an approach where fixed charges are levied on capacity ($/kW/month) and variable charges are levied on energy ($/MWh). Retail tariffs are set in different ways based upon the regulatory regime of the particular jurisdiction, the technology available (i.e. smart meters) and the economic strategy of the individual retailer. The distribution and transmission component of the end retail tariff is generally a 'pass-through' cost which is not varied by the retailer. The wholesale component and retail margin are essentially the points of difference between individual retailer offerings to consumers.

There are generally three types of end-user pricing: average flat tariffs (including peak/off peak differentiated tariffs); inclining/declining block tariffs; and ToU pricing. These are described in greater detail below:

- <u>Flat tariffs:</u> Flat tariffs are based on the average cost incurred to supply a customer with generation from the wholesale market. Flat tariffs developed in electricity markets where smart metering technology did not exist and pricing as a function of time was therefore impracticable. An early form of ToU pricing based upon 'peak' and 'off-peak' consumption utilising two separate simple accumulation meters is in place in many jurisdictions. As outlined above, some flat tariffs pass-through network tariffs which have both a fixed capacity and variable usage charge.

- <u>Inclining/declining block tariffs:</u> An inclining block tariff system is based upon 'blocks' of energy (not capacity – this is an important distinction) consumption having different tariffs. For example, a consumer might pay $200/MWh for the first 7MWh of consumption and then $300/MWh for any MWh consumed over and above 7MWh. The purpose of these tariffs is to discourage (inclining) or encourage (declining) electricity use by utilising a form of second-degree price discrimination.

- <u>ToU tariffs:</u> As the name suggests, ToU pricing is based upon pricing which varies between individual time periods, whereby electricity is more expensive at peak times, and less expensive during periods of lower demand. The advent of smart metering technologies where electricity consumption can be recorded digitally every few minutes has been a necessary development for the adoption of ToU pricing.

ToU pricing has its origins in *congestion pricing* theory. As far back as 1920, economists such as Pigou (1920, p.194) suggested that taxation may be required to optimise transportation economics. Lindsay (2006) demonstrates that the history of congestion pricing has focused on alleviation of congestion in transport. There is an important distinction between the economic literature associated with ToU pricing in electricity and transport. While congestion is often an issue in transport (i.e. commuter travelling times at peak periods are significantly slower than average), electricity markets are characterised more by continuous building of capacity with low utilisation rates.[2]

In this context, it is worth noting that much of the discussion around the need for ToU pricing is based upon macroeconomic objectives such as lowering peak demand and thereby avoiding capital expenditure on networks which are significantly underutilised. For example, the recent studies by Faruqui, Hledik and Sergici (2009) and Faruqui, Sergici and Sharif (2009) have observed that interval meters, time-of-use tariffs, and smart appliances have achieved sustained

[2] In fact, if transport markets responded to congestion in the same way as electricity, motorways or freeways would be continuously expanded with many of the new lanes utilised for only small proportions of the year.

peak load reductions of between 6 percent and 15 percent by electricity utilities in the U.S. and in Australia. However, there is little discussion in these studies in relation to alternatives to tariffs as a function of time which achieve the same objectives: pricing which reflects underutilised capital.

To analyse these existing end-user tariffs (comprised of wholesale, retail and network components aggregated together) and the new alternative forms of electricity pricing proposed in this paper, we propose the following assessment criteria for comparing the efficiency and efficacy of tariff structures:

1) The costs of shared network assets should be apportioned to those users most responsible for the costs incurred (i.e. cross-subsidisation between different customers should be minimised);

2) Any changes to tariff structures should be rate-of-return neutral for infrastructure providers (e.g. network businesses) all other things being equal. The ability of these businesses to recover their aggregate costs should neither increase nor decrease substantially from the introduction of new tariff structures;

3) Security of supply should be maintained. For example, the Australian NEM reliability standard that determines that unserved energy in a region must not exceed 0.002 per cent of total energy consumed in a year should be maintained;

4) Tariffs should provide appropriate pricing signals for individual users to adjust demand based upon economic value. This may have a system-wide effect of reducing peak demand growth and the associated infrastructure costs, as well as reducing total electricity demand and potentially greenhouse gas emissions.

5) Tariff structures should be designed with a long-term objective of reducing the total energy costs to society.

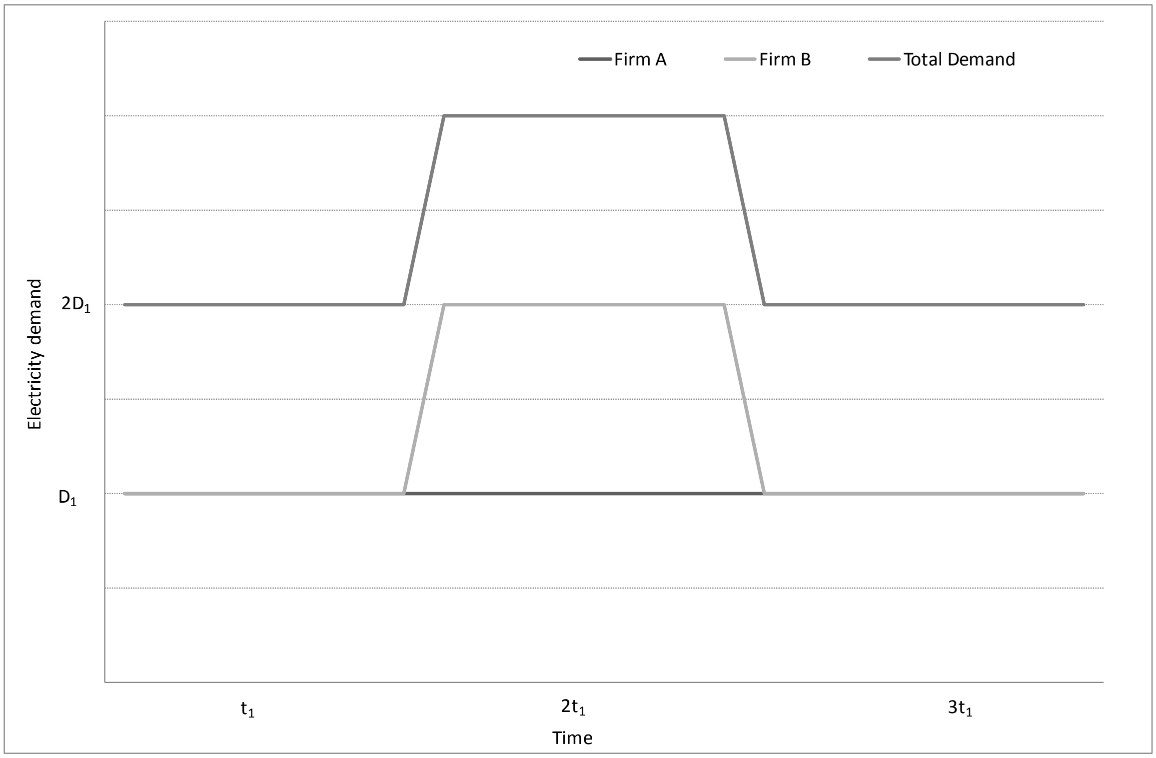
In short, tariffs should be designed to maximise fairness and efficiency, and to drive productivity improvements throughout the economy.

3. Misallocation of Costs in Average Cost and Time of Use Congestion Pricing

While ToU pricing provides greater incentives for reducing consumption at times of peak demand, it does not discriminate on the basis of individual user demand variability. This is important because a user with a stable and flat demand curve (as a function of time) is effectively cross-subsidising a user with a highly variable demand curve (as a function of time). Customers with predictable and relatively flat demand profiles are cheaper to serve than customers with peaky or unpredictable consumption patterns (or worse both). This is because cheaper baseload generation technologies can be built and deployed to service customers with stable demand, and networks with underutilised excess capacity do not need to be constructed and maintained to meet their needs.

We demonstrate this concept by presenting a hypothetical electricity network with two customers: Firm A and Firm B. We have limited our analysis in this hypothetical example to an examination of network costs for simplicity (since network charges are largely regulated as flat tariffs) but the conclusions are valid for overall tariffs which incorporate wholesale energy market pricing. The demand curve for each is shown in Figure 1.

Figure 1: Demand as a function of time for two hypothetical customers



In this scenario, Firm A has a 'flat' demand curve with constant electricity demand (D_1) during the course of a time period broken into three equal parts (t). In contrast, Firm B has a 'peaky' demand curve with variable electricity demand. For two of the three time periods, Firm B has the same demand for electricity (D_1) but in the remaining period, has twice the demand ($2D_1$).

Limiting our analysis to a simplistic network model, the total costs (TC) of meeting electricity demand in this scenario are related to the annualised cost of building the electricity network (Capex). If we assume the unit cost of expanding a network is a linear function (i.e. the cost of adding capacity is $X per MW of transmission/distribution capacity)[3], we can state that the price paid in $/MWh is likely to reflect the average costs incurred to supply Firm A and Firm B in proportion to their demand when it is constant. However, this relationship breaks down with variable demand and it is this breakdown in correlation that makes both average unit pricing and ToU pricing incompatible with a user pays pricing mechanism.

The total costs (TC) for Firm A and B are expressed below:

$$TC_A = D_1 * Capex_D \text{ ; and} \qquad (3.1)$$

$$TC_B = 2D_1 * Capex_D \qquad (3.2)$$

If each of these entities were required to pay for all of their costs in an independent system based upon individual usage, then they would have prices of

[3] This assumption has been made for simplicity of analysis. While in reality, the relationship may be non-linear, it will not impact on our conclusion

$$P_A = \frac{D_1 * Capex_D}{D_1 * t * 3} = \frac{Capex_D}{3t} \qquad (3.3)$$

$$P_B = \frac{2D_1 * Capex_D}{D_1 * 2t + 2D_1 t} = \frac{Capex_D}{2t} \qquad (3.4)$$

Let us now consider how these total costs would be allocated using a flat tariff system. Using 'flat' or 'average' tariffs, the total costs are essentially spread across the total MWh consumed irrespective of the time of consumption. In our example, it would result in a flat tariff (P_{FT}) of:

$$P_{FT} = \frac{TC_A + TC_B}{3D_1 t + 4D_1 t} = \frac{3D_1 * Capex_D}{7D_1 t} = \frac{3 * Capex_D}{7t} \qquad (3.5)$$

Therefore:

$P_A < P_{FT} < P_B$

It is clear that there is a cross-subsidy between Firm A and Firm B when a flat tariff is used to recover the total costs of building a system to supply maximum demand of $3D_1$ (aggregate demand of Firm A (D_1) and Firm B ($2D_1$)). The flat tariff is higher than the tariff that Firm A would be required to pay and lower than the tariff that Firm B would be required to pay in an independent system. This is a function of the costs being incurred in building capacity that is required by Firm B for only one-third of the time.

Now let us consider the ToU pricing scenario. In a ToU pricing scenario, the price would reflect the cost of meeting demand in each time period. In our simple scenario, there would be three effective time periods. We have called the time periods of flat demand P_1 and P_3 with the peak demand period called P_2. The price in each period where the costs are recovered in the relevant time-period would be represented by:

$$P_1 = P_3 = \frac{\frac{1}{3} * 2D_1 * Capex}{2D_1 t} = \frac{\frac{1}{3} Capex_D}{t} = \frac{Capex_D}{3t} \qquad (3.6)$$

$$P_2 = \frac{(\frac{1}{3} * 2D_1 * Capex) + D_1 Capex}{3D_1 t} = \frac{5Capex_D}{9t} \qquad (3.7)[4]$$

Consequently

$P_A = P_1 = P_3 < P_B < P_2$

[4] Note that one third appears in the numerator of equation 3.6 and equation 3.7 because the total capital expenditure is to be recovered over three time periods. If the example were extended to ten time periods, the term would be replaced by one tenth.

Based upon this analysis, it is clear that ToU pricing is a better outcome than the flat tariff for the periods of flat demand. In fact, the price in periods P_1 and P_3 is effectively the same price that Firm A would face in the independent system. However, in the period of peak demand, the price being paid is significantly different to the actual costs incurred in supplying the different customers. Firm A is effectively paying a price two-thirds higher than the costs related to its supply.

While the analysis in our hypothetical example focused on the network tariff, the conclusions are equally as valid for overall retail tariffs (incorporating the network tariff as a "pass through" to the customer) based upon operation of the wholesale market for electricity generation. This is because servicing peak demand is more expensive than underlying energy demand. This is demonstrated by analysis of the Long-Run Marginal Costs (LRMC) associated with operating peaking power stations such as OCGT (which generally have capacity factors of less than 10%) and baseload coal or gas (CCGT) alternatives. ACIL Tasman (2009) demonstrates that LRMC of an OCGT is approximately double that of coal and gas (CCGT[5]).

In our hypothetical economy, Firm A could be supplied solely by baseload generation, either through the wholesale spot market or the contract/derivatives market. The stability and predictability of its demand would enable the retailer to effectively manage the risks of the energy spot market variability through hedge (swap) contracts with generators. Alternatively, vertically integrated energy utilities could construct new, low-cost baseload generation capacity (with guaranteed utilisation) to supply these customers, should the LRMC of coal or gas (CCGT) prove a better option that purchasing energy from the spot market. Both the costs and risks associated with supplying firm A with energy are relatively low.

The difference between Firm B's peak demand and underlying demand (D) is likely to be supplied by an OCGT peaking power station at almost double the cost. In a ToU pricing scenario, both Firms A and B would be required to pay higher tariffs at times of peak demand even though Firm B is solely responsible for the peak, and therefore the technology required to supply Firm A (and its cost) would not change. While an inherent cross subsidy is possible, where prices are deregulated, energy market participants often adjust tariff offerings for larger customers based upon knowledge of a customer's load profile. The ability to accurately pass through costs for residential customers in the same way is limited by any form of retail price regulation.

4. Macroeconomic costs associated with ToU pricing

As outlined in the previous section, the fundamental limitation of ToU congestion pricing for network and retail (end-user) tariffs relates to the misallocation of costs to users based upon their demand functions. This is an important conclusion as in many electricity markets, demand as a function of time is more variable for users that are not producing goods and services (i.e. households). This is demonstrated in Table 1 for NSW and QLD, two jurisdictions within Australia.

[5] Combined-cycle gas turbine

Table 1: Utilisation rates for capital in NSW and QLD

	NSW Total Demand	NSW Residential Demand[6]	QLD Total Demand	QLD Residential Demand
Maximum Demand (MW)	13,812	4,721	8,413	2,386
Energy Demand (GWh)	78,289	16,869	52,183	8,791
Utilisation Rate (%)	64.7	40.8	70.8	42.1

Source: Simshauser et al (2011)[7]

Table 1 demonstrates why our findings in Section 3 are important in the context of broader macroeconomic objectives. The utilisation rate of households (around 40%) is far lower than the average economy (between 65% and 70%) which is indicative of the greater uptake of spatial heating and cooling devices which are only operated by households for very short periods of time over the course of a year. A ToU pricing scenario would see businesses producing goods and services effectively cross subsidising households by paying for a proportion of this underutilised capacity.

While providing an estimate of the reduction in economic activity associated with the cross subsidisation inherent in ToU pricing is beyond the scope of this paper, we note that the effective cross-subsidisation is likely to become more pronounced as utilisation rates deteriorate even further. Nelson, Kelley, Orton and Simshauser (2010) considered the Australian Energy Market Operator's (AEMO) forecasts for peak and underlying energy demand and found that the ratio of peak to underlying energy demand growth in Australia is likely to be between 113% and 183% over the coming decade. Based upon this data, it is critical for policy makers (considering regulated network tariff structures) and energy market participants to consider alternatives to ToU pricing to ensure that the cross-subsidisation between business and households is slowed or reversed.

5. A new approach to congestion pricing

The most elegant solution to pricing electricity efficiently would be to charge each user for the capacity required in addition to an energy based tariff, taking into account the variability in demand (which affects the risk and cost to serve, as demonstrated in Section 3). While some forms of this pricing exist (see Energex (2010)), they are generally not based on ToU. Furthermore, it is likely to be difficult to apportion costs (which are often not a linear function of demand) to individual users on the basis of their capacity requirements in a simple fashion. In fact, it may be that several different capacity and usage rates would be required to provide revenue neutrality. Accordingly, some form of congestion pricing is more likely to be required.

Traditional models of congestion pricing have focused on tariffs as a function of time. However, it may be that tariffs (both network and end user retail prices) set as a function of demand variability (which manifests itself in underutilised capital – the source of current electricity market inefficiency) are better placed to proportion incremental costs to responsible end users. While price discrimination on the basis of quantity purchased is not a new concept, traditional models of price discrimination are based on a single point in time purchase. For example, a

[6] Customers on regulated tariffs

[7] The data shown for residential electricity demand is based upon the profile of demand for Electricity Tariff Equalisation Fund (ETEF) customers in NSW and the Net System Load Profile (NSLP) in QLD

supplier of widgets will provide a buyer with a lower price for a higher quantity purchased at any point in time. This is a function of lower unit costs due to expanding production and reducing the Long-Run Average Cost (LRAC) of supply. This is very different from the price discrimination proposed in this paper where price is a function of the change in demand.

There are two measures that provide a useful starting point for demand variability based upon the availability (or not) of smart metering technology:

- First derivative of the individual user demand curve. By examining the rate of change, reflected in the first derivative of the individual user demand curve, it is possible to reflect the utilisation of network capital (and the requirement for more expensive peaking generation capacity) by the individual user and therefore price electricity accordingly. The provision of smart metering technologies with detailed demand data would allow this calculation to be made with tariffs based on three potential sources of data: overall market demand at a point in time (reflecting a ToU price), the rate of change for the individual users at the point in time; and actual usage. First derivative pricing could be applied to customers currently on ToU tariffs.

- Load factor of the individual user demand curve. While the first derivative calculation method outlined above would provide very specific and efficient pricing outcomes, it would require significant smart metering and computing capabilities. If smart meters were not deployed, an alternative option could be the use of a load factor for the individual user. This would provide a more simplistic (but similarly useful) indication of the rate of change of a customer's usage and a measure of capital underutilisation. A limitation on this approach is that some existing meters would require a simple adjustment to record peak demand. Load factor pricing could be applied to customers currently on flat tariffs.

Let us consider the first derivative example with our simple electricity market presented in Section 3. In the second time period, we calculated the price of electricity using a ToU tariff for the period of high demand in Equation 3.7. Let us consider how that price could be altered based upon knowledge of the rate of change for each customer. The rate of change for each customer during the period of high demand can be expressed using the following functions where demand D = f (t) is a discrete function.

$$f'(t)_A = \frac{dD_A}{dt} \approx \frac{\Delta D_A}{\Delta t} \qquad (5.1)^8$$

$$f'(t)_B = \frac{dD_B}{dt} \approx \frac{\Delta D_B}{\Delta t} \qquad (5.2)$$

The implications that can be drawn from Equations 5.1 and 5.2 is that the rate of change for Firm A is 0 (stationary demand over time) and Firm B would have a significant positive first derivative value between time periods 1 and 2 and a significant negative value between time periods 2 and 3. We can therefore conclude that the higher price (Equation 3.7) is driven by the rate of demand increase of Firm B.

[8] Note that for linear functions the first derivative will exactly equal the rate of change of demand over time. For polynomial demand functions, as Δt approaches zero, ΔD/Δt will become an increasingly accurate measurement of the first derivative of the demand function, for each time period (Δt) considered.

We can apply this information to the ToU tariff (Equation 3.7) to distribute the costs more equitably across the users. This new First Derivative Ratio (FDR) pricing can be expressed as a function outlined in Equation 5.3.

$$P_{FDR} = P_{ToU} * \beta \tag{5.3}$$

Where β is a measure of rate of change for the individual user, with a high β value indicating high rates of change, and a low β value indicating zero or low rates of change in demand over time.

β should be calculated in such a way that it reflects the arithmetic average of the absolute value[9] of the first derivative of a customer's demand curve over the ToU measurement period, and that ensures that the tariff structure change is revenue neutral. That is:

$$\begin{aligned} &\sum_{t=1}^{n} P_{FDR,A} * D_A + P_{FDR,B} * D_B + \text{K} + P_{FDR,X} * D_X = \\ &\sum_{t=1}^{n} P_{ToU,A} * D_A + P_{ToU,B} * D_B + \text{K} + P_{ToU,X} * D_X \end{aligned} \tag{5.4}$$

Where P_{FDR} and P_{ToU} are the FDR and ToU electricity prices (respectively) and D is the demand at time period t for each customer (A to X).

While the total revenue collected across the system will be the same as for ToU tariffs, the total costs incurred by individual customers may increase or decrease with the removal of the cross-subsidisation. When considering the example in Section 3, it is clear that applying the β to the original ToU price will result in a correction of the misappropriation of costs created by ToU pricing. The price paid by Firm A would be lower than the price paid by Firm B. Accordingly, Firm A would not be cross subsidising Firm B.

Importantly, in practice a constraint would need to be applied to the β to ensure that perverse outcomes do not occur. In our hypothetical example, the β would need to be constrained to ensure that the absence of a rate of change did not result in the P_{FDR} for Firm A being zero. A more precise β could be defined to ensure that prices paid are perfectly correlated with the actual costs incurred. However, defining a β that allows companies to charge every user a specific price at any point in time based upon their first derivative function is unlikely to be practicable. Such a pricing methodology would require much more sophisticated billing systems than are currently in place, and would be very difficult to explain and sell to customers (since tariffs would change in real time and could not be calculated before they are incurred).

In practice, network tariffs and retail tariffs could be set in 'groups' or 'bands' with customers who have a particular type of first derivative function at a particular time of the day. The matrix in Table 2 outlines how this could work in practice with a hypothetical example.

Table 2: Matrix of pricing options using FDR pricing

	Zero/ Small β	Moderate β	Large β
Peak	Price 1	Price 3	Price 5
Off-peak	Price 2	Price 4	Price 6

[9] The absolute value of the first derivative recognises that both upward and downward demand variability impact on cost to serve.

Table 2 presents a simple example where customers would be charged one of six potential prices at any point in time. The prices would be based upon: the time of demand (i.e. peak or off-peak) and the first derivative function of the individual customer's demand at that point of time (zero/small, moderate or large). At times of peak demand, customers would be provided with a simple decision: maintain consumption at previous levels and be charged Price 1; increase consumption by a small amount and pay a higher price (Price 2); or significantly increase consumption and pay a much higher price (Price 3). Effectively, the customer is facing an inclining block tariff for that moment in time at which peak demand occurs. While this is a relatively simple decision to make for each consumer, we believe that such a pricing system would only be effective if coupled with a comprehensive consumer education campaign.

By grouping customers into three broad types of user, the calculations necessary to determine the exact β factor required are significantly reduced. In practice, the network regulator or electricity retailer would optimise this calculation. It could be argued that such an approach provides significant advantages over the alternative pricing of both capacity and energy. This is because pricing is still partially a function of time and the benefits of critical peak pricing identified in studies such as Faruqui (2009) are likely to continue to apply. We accept that more work is needed to test how such a pricing system would apply in practice. However, we note that consumers have adjusted their behaviour in response to pricing structures that could be argued to be equally complicated (i.e. inclining block tariff). Either way, this article has demonstrated that in theory, FDR pricing provides for a better allocation of costs based upon the principles of efficiency and equity.

A potential misunderstanding of the incentives created by our new pricing theory relates to consumption. As price is a function of demand, it may appear that consumers would have an incentive to consume more energy at their peak capacity to lower their unit price. While this is true, the incentive is somewhat destroyed by the higher quantity of energy consumed which would add significant costs to the consumer's bill. Accordingly, we do not believe that, *ceteris paribus*, our pricing theory would lead to over consumption. In fact, retailers would be able to offer products where the customer would pay less at times of peak demand if their usage did not increase from the previous time period.

6. Assessment of Tariff Structures

In Section 2, assessment criteria were proposed against which different tariff structures could be compared to determine their efficiency and efficacy. Table 3 assesses the different tariff designs that have been discussed in this work against the criteria. We conclude the FDR pricing best meets the established criteria.

Table 3: Assessment of different tariff designs against proposed criteria

Criteria	Assessment
The costs of shared network assets should be apportioned to those users most responsible for the costs incurred	Section 3 demonstrated that there is significant cross-subsidisation between customers when using ToU, flat and block tariffs. This arises because the costs of underutilised infrastructure are spread across all energy customers, rather than being focused on those customers which are most responsible for the incurred costs. Section 5 shows that the proposed FDR pricing structure minimises this cross-subsidisation.
Changes to tariff structures should be rate-of-return neutral for infrastructure providers	Section 5 demonstrates how FDR pricing can be designed so that it is revenue neutral. Importantly, all of the tariff structures considered can be designed so that there are no system-wide increases or decreases in revenue collected (all other things being equal).
Security of supply should be maintained	Rapid growth in peak demand increases the risk that at critical peak periods, demand may outstrip supply (leading to power shortages). Both ToU and FDR tariffs provide pricing signals for customers to reduce peak consumption and can therefore assist with ensuring security of supply. Flat and block tariff designs do not encourage customers to limit their electricity consumption in peak periods. It is clearly preferable to limit new capacity requirements by encouraging customers to voluntarily shed discretionary load at peak times based upon pricing signals, as opposed to forced load shedding (power outages).

Criteria	Assessment
Tariffs should provide appropriate pricing signals for individual users to adjust demand based upon economic value	ToU tariffs are designed to encourage customers to reduce electricity consumption at peak times, and to shift discretionary consumption to off peak periods where possible, in order to reduce costs. A common criticism of ToU pricing is that it unfairly penalises those customers which have limited capacity to change their consumption behaviour. The advantage of FDR over ToU pricing is that it takes into account the utilisation of capacity rather than only the time at which energy is consumed. Customers who have relatively high yet stable consumption patterns are not penalised for their inability to switch off essential consumption during peak demand periods. Furthermore, those customers who are most responsible for underutilised infrastructure tend to contribute to peak demand via more discretionary consumption (such as spatial heating and cooling). FDR pricing is therefore likely to provide at least as much incentive for customers to adjust their demand as ToU, with the added benefit that FDR better targets more discretionary consumption. Flat tariffs do not reflect the economics of supplying customers with energy. While inclining block tariffs provide some incentive for customers to curb energy consumption above a certain threshold, there are no price signals for customers to adjust either the time or variability of their consumption. Block tariffs can also disadvantage large households, or those customers with high non-discretional consumption.
Tariff structures should be designed with a long-term objective of reducing the total energy costs to society	Electricity tariffs should not be designed to restrict customers from consuming electricity when they need to. Rather, tariffs should reflect the actual costs of electricity supply, and allow customers to optimise their position by making trade-off decisions between energy use and cost. Such a system would minimise costs, while ensuring that electricity is available for essential and productive purposes. Both ToU and FDR pricing are designed to approximate true costs to serve, which encourages customers to adjust the way they consume energy in ways which also reduces the total energy costs to society. While ToU tariffs encourage customers to shift discretionary consumption to off peak periods, FDR pricing encourages customers to self regulate, in order to 'smooth out' their demand profiles as much as possible (for low rates of change). On a system-wide scale, this should make demand more stable and predictable, enabling cheaper baseload generation to be deployed to meet a greater proportion of demand. It should also increase the utilisation of network capacity (and reduce the requirement to build new capacity). This may see a reduction in both the costs of electricity provision, and prices of electricity in the medium to long term.

7. Policy Implications and Concluding Remarks

This study has demonstrated that both end-user and network ToU pricing is not effective for allocating costs equitably in a congested electricity market. While the focus of congestion pricing theory has generally been on *time*, this study has shown that high unit costs are a result of excess capacity created due to low time utilisation of infrastructure. Allocative or pricing efficiency can only be achieved where end users are exposed to the costs associated with consumption of the good or service. In this context, the focus on *time* in ToU pricing rather than demand variability ignores the fact that only users with variable demand contribute towards underutilisation of capacity.

A potential solution for allocating costs appropriately in a congested electricity market is the use of FDR pricing[10]. This new form of pricing effectively introduces a new variable into the tariff structure: the rate of change of the individual customer's electricity demand. The variable reflects the customer's actual contribution to peak demand and underutilised capacity in other time periods. Customers with higher first derivative demand functions would pay a higher electricity price than customers with lower first derivative demand functions. This methodology would more effectively allocate the costs associated with peak demand events to the customers who increase their usage at times of peak demand.

We believe that there are likely to be significant macroeconomic benefits associated with the introduction of first derivative ratio pricing in many countries including Australia. At present, peak demand events are generally a function of household space heating and cooling consumption patterns. This is manifesting itself in a significant cross-subsidisation between households and business end-users. With ToU pricing in place, commercial and industrial users with lower rates of demand change will be effectively cross subsidising households with higher rates of demand change. This unnecessarily constrains economic activity. First derivative ratio pricing would overcome this shortcoming in ToU pricing.

First derivative ratio pricing would require the introduction of smart metering technology which allows the rate of demand change between time periods to be calculated. If smart meters are not in place, a simpler alternative could be introduced based upon a customer's load factor. An accumulation meter that records peak demand and underlying energy demand would allow peak pricing to be reduced for a customer with a high load (utilisation) factor and increased for a customer with a low load factor. While not as precise as first derivative ratio pricing, this could be introduced as a stop gap measure until smart metering is introduced.

It is critical that policy makers consider the findings of this paper in the context of four broad public policy debates:

- Form of regulation for regulated networks. Network regulation entities (such as the AER in Australia) should consider first derivative ratio network pricing as a way of ensuring that network costs are allocated efficiently and equitably to end users. With smart metering in place, network prices with a first derivative component would be better suited to incentivising users who contribute to peak demand to reduce consumption at these points in time.

[10] The applications of first derivative ratio pricing are likely to go beyond electricity markets. In transport markets, policy makers may find that relatively constant users of roads (such as buses and heavy trucks) should be exempt from congestion charging.

- Deregulation of retail pricing. In markets where competition is effective at the retail level, regulation of prices by government must be removed. Regulation of retail prices ensures that households without peak space heating and cooling demand subsidise those that do. This is inequitable and is likely to have significant adverse social policy implications. In addition, the introduction of first derivative ratio pricing provides another point of difference for retail product offerings and is therefore likely to enhance competition.

- The introduction of smart metering technologies. Smart meters are being progressively installed by jurisdictions around the world. The use of first derivative ratio pricing can now be considered as a 'benefit' in any cost-benefit analysis undertaken to determine whether smart meters should be introduced.

- Public education. Electricity markets are not easily understood by customers. Congestion pricing is a much more tangible concept to understand in transport where traffic jams are a visual representation of its manifestation. Generally, households are not aware that they are already receiving significant cross subsidies from other users and that this will continue under a ToU pricing regime. Households are not being informed about the issues related to underutilised capacity and higher overall prices as a result of peak demand for space heating and cooling. Governments must begin to educate the public in relation to the operation of electricity markets and the need to price electricity appropriately.

One way of incentivising and educating customers while making use of the smart meter is to produce two bills for each customer during a transitional period; one with the existing tariff and the other based on the new pricing methodology. Of course, the customer would continue to pay for their electricity usage based upon the existing tariff. However, the potential benefits of time shifting would be visible to the customers, leading to potential changes in their consumption behaviour.

In conclusion, we believe that the new form of pricing introduced in this paper is likely to have significant benefits if applied in electricity markets. However, policy makers and companies need to be thoughtful in its application. Electricity is generally regarded as an essential service and as a commodity is not well understood by the public. Honebein (2010) outlines a number of sensible suggestions in relation to how new concepts should be explored in electricity markets. The provision of information ahead of time is a critical factor in the success or failure of any new concept in these markets. As such, before first derivative pricing could be successfully introduced, a widespread public education campaign about its benefits would be required.

8. References

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