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Declan Kelly

An Assessment of the Cost-Reflectivity of Proposed Network Tariffs in Australia

Declan Kelly[1], Anna Bruce[1], Iain MacGill[2] and Robert Passey[2]

1. School of Photovoltaic and Renewable Energy Engineering, UNSW, Sydney Australia

2. Centre for Energy and Environmental Markets and School of Electrical Engineering and Telecommunications, UNSW, Sydney, Australia

E-mail: declankellyunsw@gmail.com

Abstract

Network tariffs in the Australian National Electricity Market (NEM) have received growing attention in recent years as the main contributor to rapidly rising electricity bills for residential and small business customers. A number of government enquiries in 2012 and 2013 found significant overspending by networks, and a need to review regulations that had encouraged network over-investment in order to expand their regulated asset base.

In response, the Australian Energy Market Commission (AEMC) has introduced a rule change that requires Distribution Network Service Providers (DNSPs) to implement tariffs that better reflect the cost of providing network services to customers. The aim is to achieve more economically efficient use of the network by pricing the network service correctly and hence driving more appropriate end-user levels and patterns of electricity demand. The rule specifies that tariffs must now be based on the long run marginal cost (LRMC) of providing additional network capacity and that the residual costs (the sunk network costs) should be recovered in a way that does not distort the LRMC price signal. There is, however, a lack of clarity in the rule about how the LRMC-based tariffs should be calculated and how the residual costs should be recovered.

This paper presents the outcomes of a study that assesses the cost-reflectiveness of network tariffs proposed under the new rule by Australian DNSPs, as well as tariffs put forward by other stakeholders. The study uses load data from 300 households located in one of the DNSP areas. The tariffs are assessed against a range of design criteria, including the extent to which they reflect the LRMC of the network and account for geographical differences, and the extent to which the pass-through of residual costs distorts the ‘efficient’ pricing signal provided by the LRMC. The study also considers the extent of cross subsidisation between customers under each of the assessed tariffs, and how this varies for different locations in the network with different LRMCs.

Developing cost-reflective tariff structures is a highly complex process and the proposed solutions may not be ideal. This study finds that the demand charge-based tariffs proposed thus far may not be more cost reflective than current pricing structures. If a transition is made towards implementing demand charge-based tariffs, more attention needs to be placed on their design, and greater consideration of spatial variation in network conditions is required to minimise cross subsidies and maximise cost-reflectivity.

1. Introduction

Falling electricity demand, rising household electricity bills and the emergence of disruptive end-use energy technologies have prompted growing discussions in Australia and elsewhere about the future of energy consumer arrangements in the electricity industry. The traditional electricity model was designed to facilitate the flow of energy from large-scale generators through networks to end-users. Under such arrangements, end-users were generally considered to be passive participants (AEMC 2014), but are now increasingly being seen as potentially highly active participants in the electricity industry. New arrangements are required to effectively integrate them into broader industry decision-making (AEMC 2014).

Network regulatory arrangements have been particularly problematic in Australia over recent years. While electricity industry restructuring has introduced competition into the wholesale and retail sectors, networks remain under a monopoly economic regulation framework (Productivity Commission 2013). Network tariffs are proposed by distribution network service providers (DNSPs), and assessed by the Australian Energy Regulator (AER) within jurisdictional guidance (AER 2015), as part of a three yearly price determination process. Larger customers are billed for their metered use of the network, while for smaller customers, network tariffs have traditionally been fairly simplified, particularly as the majority of small customers have only accumulation metering. These network tariff arrangements have involved considerable cross subsidies; notably between urban and regional and rural consumers, and between consumers with different levels of peak demand. As such, network tariffs have not been economically efficient in terms of sending appropriate signals to consumers about the economic implications of their location, building stock and appliance investments, and patterns of energy use. Such failings have been seen as particularly problematic in the context of rapidly growing network expenditure and hence tariff rises over the past decade in Australia. In practice, however, there are potentially significant complexities in determining economically efficient tariffs which should, in theory at least, vary over time and location subject to aggregate levels and patterns of demand in different parts of the network (AEMC 2014). Location is important because different parts of the distribution network have different operational and augmentation costs.

The Australian Energy Market Commission (AEMC) has undertaken three demand side participation reviews over the past decade, the third referred to as the Power of Choice review. The Power of Choice review led to multiple recommendations for updating the National Electricity Rules (NER), in order to better facilitate end-user participation in the National Electricity Market (NEM). One of the rule changes is the distribution network pricing arrangements determination (AEMC 2014). The majority of discussion resulting from the determination to date has centred on how cost reflective tariffs should be designed. Networks NSW, a business which arose from the merger of the three NSW DNSPs, argued that there should be no mandated tariff design (Networks NSW 2014) in submissions to the rule change process, leaving room for DNSPs to specify their preferred method.

The final determination mandates that distribution network tariffs must be based on the long run marginal cost (LRMC) of supply without specifying which method should be used to determine the value of LRMC. LRMC is an economic measure of the future costs to the network associated with present use. The new tariffs should therefore provide end-users an indication of the future network investment costs associated with their use of the network. However, the rule change has provided little specific guidance on how DNSPs should implement such 'cost reflective' tariffs.

In addition to lack of clarity about how LRMC should be calculated, the recovery of the LRMC alone does not provide sufficient revenue for the sustainable operation of network businesses (NERA 2014). Network businesses need to recover 'sunk' investment costs, often termed the residual costs. The AEMC determination provided limited guidance on the recovery of residual costs, except to specify that when recovered through network tariffs they should result in minimal distortion to the price signal associated with the LRMC (AEMC 2014). If efficient pricing were the only relevant consideration, pricing theory dictates that residual costs would be recovered through a fixed charge, however this is perceived as inequitable so the residual is currently being at least partially recovered through energy charges (Faruqui and Brown 2014).

Whilst the rule change has yet to come into effect in most jurisdictions, initial cost-reflective tariff designs have already been proposed by various DNSPs. The extent to which the proposed tariffs are cost-reflective has not yet been conclusively assessed by DNSPs, while broader considerations such as equity, impartiality, and gradualism (facilitating significant change through regular incremental change) have been used as partial justifications for tariff designs.

This paper aims to explore the extent to which existing, proposed and possible future network tariffs align payments by different customers for use of the distribution network with the costs that these customers impose on the network. Section 2 explores the context for the research. Section 3 outlines the methodology, assumptions and data sources used in developing the model used to assess network tariffs. Section 4 presents the results from the modelling work and analyses the results and implications for appropriate cost-reflective network tariff design. Section 5 provides the conclusions of the research, discusses the limitations, and considers the scope for future work in this area.

2. Context

Attempts at cost-reflective tariffs are not new in Australia. Currently network tariffs for large energy consumers, including commercial and industrial customers, include demand charges in most distribution networks. In contrast to residential customers, large customers generally have the metering to facilitate more complex tariffs and are more likely to be responsive to price signals. Large energy users responding to peak price events have been observed to make a valuable reduction to network constraints during peak loads (Productivity Commission 2013). Transmission use of system (TUOS) charges in the NEM are also charged with a peak demand price signal. Approximately one half of the TUOS charges are a locational component which is charged to the DNSPs according to flows at various different junctions between the transmission and distribution networks. The charge applies during the top half hourly period for each month and varies to reflect different spatial constraints (Transgrid 2015).

The LRMC of electricity services is not determined using a specified methodology but is generally approximated from the incremental costs of providing another kilowatt of power. The principal drivers of these network costs are increases in maximum demand at each network point (NERA 2014). As it would be too complex to estimate the LRMC at each point in the network, it is generally determined for each voltage level in the distribution network.

For low voltage end-users there has historically been limited discussion or implementation of tariff designs that price temporal impacts of usage, such as demand charge-based tariffs or critical peak tariffs. Energeia (2015) reported that demand tariffs perform in a more cost-reflective manner than traditional tariffs such as block tariffs and time of use tariffs. NERA

Economic Consulting (2014) also highlighted demand charge-based tariffs and critical peak pricing as two tariff structures which are able to signal the costs related to maximum demand. Ergon Energy (a QLD DNSP) and Victorian DNSPs Jemena Energy Network (Jemena) and United Energy (United) have now indicated that they will be implementing a demand charge-based tariff to meet the new cost-reflective rules.

The AEMC has acknowledged that location should also be an important factor in designing cost-reflective tariffs, and noted that if a DNSP fails to implement a pricing structure which considers the spatial variation in costs of serving customers throughout the network they would be unlikely to send efficient pricing signals to end-users (AEMC 2014). Location-based pricing has been considered for encouraging optimal investment in distributed generation (Brandstatt, Brunekreeft et al. 2011) but the impacts on end-user tariffs remains relatively unexplored. The Australian Photovoltaic Institute (APVI 2015) argued that demand-based charges should be targeting local demand. The Consumer Utilities Advocacy Centre (CUAC) also briefly mention the concept in their discussion but provide very limited detail on the effects of considering location in designing network tariffs (CUAC 2015). There is also limited consideration of location-based pricing in the tariffs proposed by DNSPs. Jemena (2015) accepted spatial variance as important but decided it presented too much complexity for end users to respond to in the short term.

The research presented in this paper will explore the cost-reflectiveness of proposed network tariff designs (the relationship between costs paid by end users and cost imposed on networks), and the extent to which cross subsides exist under different network pricing structures. There has been limited consideration to date of the extent to which tariff designs, which may be considered cost-reflective for an average customer in the network, remain cost-reflective when implemented under a range of different network conditions. This paper provides an indicative assessment of the performance of cost-reflective tariffs in different network locations, where both temporal and locational cost aspects vary.

3. Methodology

The study uses time series consumption data for 300 houses in the Ausgrid network service area of greater Sydney, along with Ausgrid's estimates of LRMC for different locations to: (i) estimate the costs imposed by different customers on the Ausgrid network, and (ii) compare these costs to the bills that they would pay for distribution network services under different tariff designs. The 300 houses are spread throughout the Greater Sydney Area and are assumed to be representative of household consumption profiles at each of the modeled substations, explained in greater detail below.

The concept of LRMC as an estimate of the future costs implies that LRMC tariffs should include current and future costs that a customer is imposing on the distribution network due to their energy consumption and peak demand. For this analysis, this is assumed to be true.

The modelling methodology is summarised in Figure 1. Ausgrid zone substation (ZS) demand (both past and forecast) and LRMC were used to develop a number of different substation scenarios (explained in more detail below). To assess the proposed tariffs, the correlation between costs imposed on the network and customer bills is examined under different tariffs and for different network locations (substation scenarios). The correlation coefficient is determined in Microsoft Excel and measures how strong a linear relationship between two numeric variables is. The extent to which cross subsidies between customers exist under the different tariffs is then assessed. A cross subsidy exists when there is a difference between the costs paid by a customer under a particular tariff and the cost they would have paid under the benchmark cost-reflective tariff. The design of the benchmark tariff, and the data used in the model are described in more detail in the following sections.

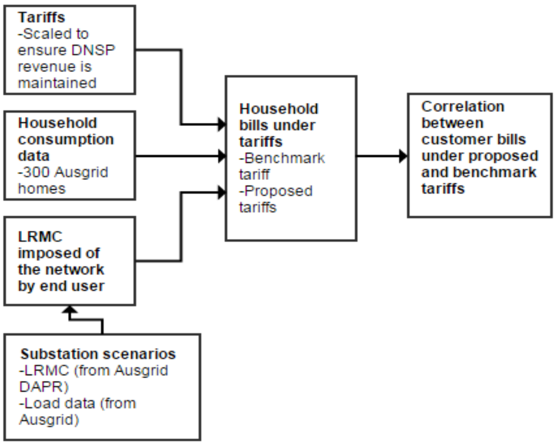

Figure 1 Summary of the Method

The modelling tests only the cost-reflectiveness of Distribution Use of System (DUOS) charges and excludes Transmission Use of System (TUOS) charges, GST and any other charges. It is assumed that the only marginal cost an end-user imposes on the distribution network is in the contribution to the local peak demand which has an associated LRMC. The transportation of electricity is assumed to have a zero cost, a common assumption when assessing network costs (Faruqui and Brown 2014). Off-peak tariffs and special tariffs such as those for ‘controlled load’ are excluded from the modelling, as they are assumed to be constant between different tariffs. The costs imposed on the network at the low voltage distribution level (which includes residential consumption) occur during the peak load of the local ZS. This assumption is supported by the peak load timing at the substations, after 5pm, which indicate that residential loads are the primary component of the substation peak load.

3.1. Data sources

The model data inputs include:

1. Residential half hourly electricity consumption data. The data set contains 300 houses and consumption values from the 1st June 2010 to the 1st July 2011. This dataset was made public by Ausgrid (Ausgrid 2014).
2. The network-wide LRMC value and assumed power factor for low voltage consumption Ausgrid’s network provided in the 2014/15 Ausgrid pricing proposal (Ausgrid 2014).
3. Tariff structures submitted to the AER in the 2014/15 Ausgrid pricing proposal.
4. Demand forecasts and network capacity at different zone substations from Ausgrid’s Distribution and Transmission Annual Planning Report (DAPR) (Ausgrid 2014).
5. Load profiles for the zone substations made publicly available on Ausgrid’s (Ausgrid 2015) website.

3.2. Substation scenarios

Three zone substation scenarios were considered for this model; a low LRMC substation, a baseline substation and a high LRMC substation. Matraville ZS was selected from the Ausgrid DAPR to represent the low LRMC substation scenario, due to the excess capacity and falling peak demand seen in that area over recent years. The LRMC for Matraville ZS was assumed to be 50% of the network-wide average LRMC. The peak demand periods at Matraville ZS were taken from the load profile for the Matraville ZS made available by Ausgrid (Ausgrid 2015). The baseline substation was designed to be representative of the average substation in Ausgrid's network. The costs imposed on the network at the baseline substation were attributed to peak demand periods in summer months, between 4pm and 8pm, typical residential peak hours (Productivity Commission 2013) and the associated LRMC is the network wide average value provided by Ausgrid. Edgeworth ZS was selected to represent a high LRMC scenario due to limited firm capacity and rising peak demand at that ZS over recent years. The LRMC for Edgeworth ZS is taken to be twice the network average LRMC and the peak demand periods were taken from the load profile for the Edgeworth ZS made available by Ausgrid.

3.3. Tariffs

In addition to the inclining block tariff and the time of use tariff outlined in Ausgrid's 2014/15 pricing proposal (2014), four tariffs were tested for this study. The tariffs were adapted from 'cost-reflective' tariffs proposed by the Victorian DNSPs Jemena and United, and a tariff design put forward by the Grattan Institute (Carter and Wood 2014). Each tariff was scaled to recover the same amount of total revenue from the 300 households as the existing Ausgrid inclining block and time of use tariffs, which produced an average charge of $600 and $606 respectively. After applying the demand charge for the four 'cost-reflective' tariffs, the balance of the revenue recovered under existing tariffs was recovered via a flat rate tariff on energy consumption (c/kWh), which would apply at all times. All the demand tariffs also have a fixed charge component, which is the same as for Ausgrid's existing inclining block tariff.

Table 1 Assessed tariffs

Tariff	**Reference name**
Benchmark cost-reflective tariff	CRT
Ausgrid declining block tariff.	Block
Ausgrid time-of-use tariff.	Time of use or TOU
Jemena demand charge-based tariff with flat rate energy charge.	Demand charge 1
United demand charge-based tariff with flat rate energy charge.	Demand charge 2
Grattan Institute demand-charge based tariff.	Demand charge 3
Jemena demand charge-based tariff with time-of-use energy charge.	Demand charge 4

3.3.1. Costs imposed on the network and Benchmark cost reflective tariff

The costs each end user imposed on the network were determined by multiplying the average contribution each end user made to the top five demand peaks (top five half hour loads). The average contribution was multiplied by the LRMC of each of the substations. Because the LRMC is a forward looking cost, the costs were assumed to be imposed during the top five peak hours (instead of the sole annual peak) as these peaks were all potentially representative of future demand peaks which may facilitate network investment.

A cost-reflective tariff was designed as a benchmark for testing the proposed tariffs and determining the value of cross subsidies. The benchmark tariff (CRT) is comprised of the same fixed charge as the standard Ausgrid tariffs, a flat rate energy charge and the cost each end user imposes on the network as calculated above. The energy charge is charged at a flat rate to conform to the AEMC determination which states that the residual component of the tariff should be recovered in a way which does not distort the price signal associated with the recovery of the LRMC (AEMC 2014) For this to be the case, the demand charge should account for the entire LRMC.

3.3.2. Jemena – demand tariff 1 and demand tariff 4

Jemena proposed a ‘general purpose’ demand charge-based cost-reflective tariff which is composed of a fixed charge, an energy charge and a demand charge (Jemena 2014). The energy charge is charged at the same rate at all times. The demand charge is charged to the largest customer peak for each month (on weekdays between 10am and 9pm). The demand charge is scaled from the network LRMC by multiplying the LRMC by 0.469 (Jemena 2015). The demand charge is scaled down from the LRMC to account for the demand which is billed by the demand charge but does not contribute to the costs faced by the network. It is impractical to apply the full LRMC to peak customer demand for each month. The demand charge is then equally split and applied to each month. To adapt the Jemena design to the Ausgrid distribution network, a demand charge was produced using the Ausgrid low voltage (residential connections) LRMC and the charging windows in the Jemena design. Demand tariff 4 is also adapted from Jemena proposed tariff. Demand tariff 4 has the same demand charge as demand tariff 1 but the energy charge is time-of-use as opposed to a flat rate.

3.3.3. United – demand tariff 2

United also proposed a demand charge-based tariff. The two distinctions from the Jemena design is an increased summer demand charge and a minimum demand charge. For consistency between the tariffs, the fixed charge was changed to be the same as the other assessed tariff designs. The time window in which United applied their demand charge was also considerably narrower than the Jemena demand charge time window. To adapt the United design to Ausgrid’s distribution network, a similar process was applied as was used to adapt the Jemena design, while reweighting the demand charges towards summer and changing the charging windows to the United tariff design.

3.3.4. Grattan Institute – demand tariff 3

The Grattan Institute outlined a demand charge based design in the their report on cost-reflective pricing (Carter and Wood 2014). The tariff as proposed by the Grattan Institute charges end-users for their five greatest half hourly demand periods. There is also a fixed charge, which is the same as the other tariffs assessed here.

3.4. Calculation of Correlation Values

The correlation between two sets of values was calculated using Excel’s CORREL function, which calculates the Pearson Product-Moment Correlation Coefficient.

4. Results

The costs paid by each of the 300 households in the dataset under each of the assessed tariffs, and the estimated costs imposed on the three different zone substations by these customers were calculated and analysed.

4.1. Relationship between costs paid by customer and costs imposed on network

The correlation between the customers' bills and the costs they impose on the network, as well as the correlation between the customers' bills under the tariff being tested and under the CRT are shown in Table 1. A high correlation (0.7 - 1) suggests that customers that impose higher costs on the network would pay higher costs under the assessed tariff. Similarly, a high correlation between the assessed tariffs and the CRT indicates similar customer costs under the two tariffs.

Table 2 Correlation between payment by customers and cost imposed on the network under different tariffs

	Baseline		Low LRMC		High LRMC	
Bill under tariff	Correlation between customers' bills and network costs	Correlation between assessed tariff and CRT	Correlation with cost	Correlation with CRT	Correlation with cost	Correlation with CRT
Block	0.624	0.794	0.429	0.755	0.472	0.667
Time of Use	0.786	0.955	0.553	0.906	0.606	0.818
Demand Tariff 1	0.748	0.931	0.530	0.890	0.569	0.788
Demand Tariff 2	0.782	0.944	0.507	0.873	0.587	0.799
Demand Tariff 3	0.604	0.667	0.452	0.635	0.461	0.580
Demand Tariff 4	0.774	0.935	0.557	0.893	0.594	0.801

Note: "Correlation with cost" refers to the correlation with the costs imposed on the network.

The block tariff and demand tariff 3 had the lowest correlation with both network cost and the benchmark cost reflective tariff, performing particularly poorly in non-baseline substations, that do not reflect the average. The block tariff was very poor in recovering costs from end users who impose large costs on the network. Demand tariff 3 produced poor correlation coefficients due to the poor design of the demand charge - which applies to customer peaks instead of network peaks. The window in which the charge is applied is designed in a way charges for demand which is unlikely to impact on network costs .

Although demand charges are widely touted as a more cost-reflective solution (Carter and Wood 2014), these results have indicated that time-of-use tariffs may be a more suitable solution than demand charge tariffs which have been poorly designed. Demand charges can be difficult to calculate and design efficiently. The charging windows on the proposed tariff designs are broad during each day and are over multiple months and so are likely to charge customers disproportionately to the costs they impose on the network. If demand charges are going to be efficiently implemented, greater consideration should be given to ensuring the demand charge aligns accurately with the costs imposed upon the network as well how these costs vary spatially and temporally.

Figure 4 below shows the cross subsidies received by end users under the proposed cost reflective tariffs. The cross subsidies are defined as the difference between the amount charged to end users under the assessed tariffs and under the benchmark CRT. At the baseline substation, under each tariff, the majority of end users are subsidising a small number of end users who are imposing large costs on the network. At the low LRMC substation, the large majority of end users are overcharged to subsidise end users in more expensive parts of the network. The high LRMC substation shows the converse, with the majority of customers receiving cross subsidies from the rest of the end users.

The block tariff and demand tariff 3 have the highest level of cross subsidy at each of the substations. The block tariff has a tendency to significantly overcharge the majority of end users to subsidise end users who impose large costs on the network. This is due to the sharply declining block tariff which applied large charges to end users with low consumption and/or flat load profiles. Demand tariff 3 is equally poor in minimising cross subsidies. The Grattan Institute tariff resulted in large cross subsidies at each substation which is indicative of a charging structure which fails to fairly allocate charges to the end users imposing costs upon the network.

The time of use tariff, demand tariff 1, demand tariff 2 and demand tariff 4 did much better in minimising cross subsidies at the baseline substation, with the majority of customers paying close to zero cross subsidy. These tariffs result in cross subsidies at the low LRMC and high LRMC substations. By providing tariffs which are more location specific, the cross subsidies provided and received would decrease further and result in prices which are more cost-reflective and provide more efficient investment and behavioral ‘signals’ to end users.

Cross subsidies between end users

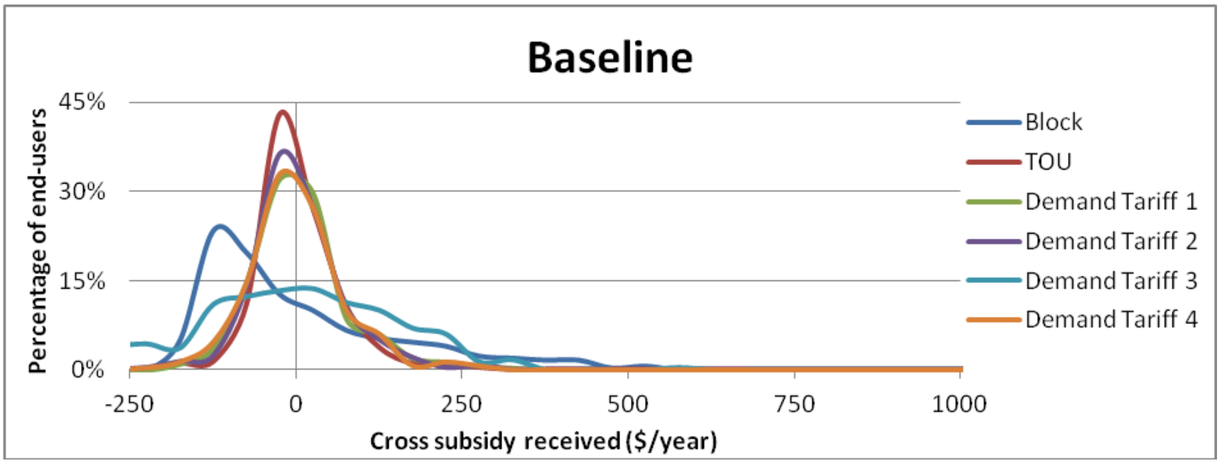

Figure 4.1 Comparison of cross subsides received under assessed tariffs – baseline

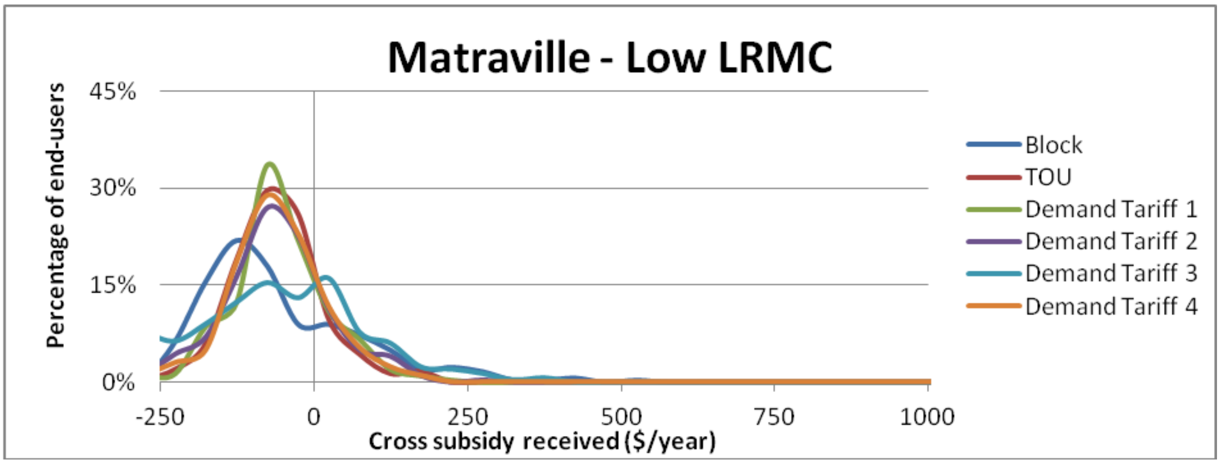

Figure 4.2 Comparison of cross subsides received under assessed tariffs - low LRMC

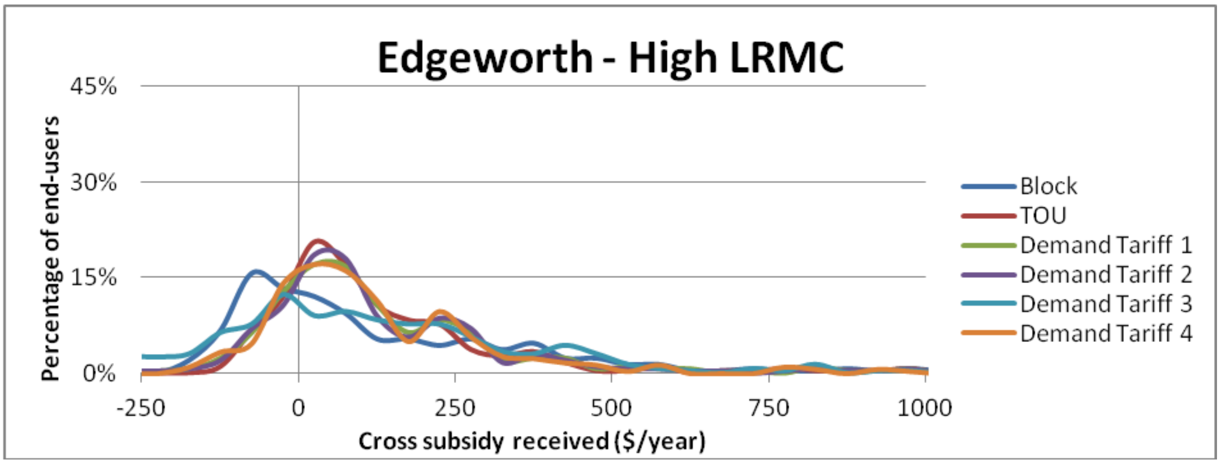

Figure 4.3 Comparison of cross subsides received under assessed tariffs - high LRMC

In assessing these results, it should be noted that the modelling relies on the design of the benchmark cost-reflective tariff. However, the emphasis here is on the relative differences between the outcomes for the different tariffs, not the absolute values. It should also be recognised that the purpose of cost-reflective tariffs is to encourage a demand response from end users. For this reason DNSPs design tariffs with consideration of the concept of gradualism to allow end users to adapt and respond, which may be used as a justification to distort the cost-reflectiveness of the initial cost-reflective tariffs (Jemena 2014).

5. Conclusion

Network pricing arrangements in the NEM are undergoing a transition to a structure which aims to facilitate end user consumption and investment decisions that use network infrastructure more efficiently. Cost-reflective network tariff arrangements will be key to such efforts but they need to be carefully designed.

The design and structure of demand charge-based tariffs has a significant effect on their cost-reflectivity. The results from this study indicate that the demand tariffs thus far proposed by DNSPs may not be more cost-reflective than current pricing structures such as time-of-use tariffs. At best, the proposed demand-charge based tariffs provide an equal level of cost reflectivity to current pricing structures. Greater emphasis should be placed on designing a demand charge window which is able to more accurately reflect network costs. A possible implementation of this is critical peak pricing which has a demand charge window limited to a small number of peak demand hours. If a transition is made towards implementing demand charge-based tariffs, there should be greater consideration of spatial variances in network conditions, in order reflect the importance of local network peaks in determining costs imposed by customers. Due to conservative choice of LRMC for the 'high' and 'low' substation scenarios, the modelling in this paper provided relatively modest examples of the cross subsidies which may be introduced if demand charge based tariffs are implemented without consideration of spatial variance in network conditions.

Developing cost reflective tariffs is a highly complex process and relies heavily on forecasting as an input to LRMC calculations. Residential photovoltaics are cited as beneficiaries of cross subsidies (Carter and Wood 2014) but this paper has indicated that under existing and proposed tariffs, cross subsidies are widespread between all end users.

There is certainly scope for future work in exploring the design and implications of cost-reflective tariffs. Further research should consider whether increasingly complex network tariffs might dampen end user response. Going forward, there should also be a greater consideration of the method for recovery of residual costs in network tariffs. If the LRMC of the network falls in the future, the residual component of tariffs will become more significant and the manner in which it is factored into the tariff design will be crucial.

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