Structure of Electricity Distribution Network Tariffs: Recovery of Residual Costs

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Executive summary

Long-run marginal costs (LRMC) are often the starting-point for setting electricity distribution tariffs because LRMC-based prices contribute to efficient decisions by end-users on the use of electricity and investment in electrical equipment. However, because LRMC is forward-looking, a tariff based only on LRMC would not recover the total cost of providing the regulated services or (equivalently) the approved revenue. The difference between the total approved revenue and the revenue that would be raised at tariffs based only on LRMC is termed the "residual" cost. The Australian Energy Market Commission (AEMC) asked us to prepare a report on how electricity distribution network tariffs can be structured to recover residual costs.

We have reviewed some 140 items in the academic literature on network tariffs, reached out to two dozen industry experts, and researched how utilities in different jurisdictions recover residual costs. We found the following principles to be relevant for structuring tariffs to recover residual costs.

- The guiding principle in the academic literature is Ramsey pricing, or the "inverse elasticity" rule. Residual costs should be recovered from the various services provided by the firm and the various groups of customers served in inverse proportion to the respective price elasticity of demand. The intuition behind this rule is that the broader goal is to have efficient tariffs based on LRMC, and that departures from LRMC induce inefficiencies. The magnitude of the inefficiencies is minimized if the movement in prices away from LRMC is concentrated on those tariffs or parts of the tariff which have the smallest elasticities.

- In practice, utilities and regulatory authorities place significant weight on equity or "fairness" considerations. We found that the "fairness principle" is subject to multiple interpretations when it comes to tariff design. In one interpretation, fairness means that tariffs should not be changed so drastically that certain customers experience large bill increases in a short period of time while others experience large bill decreases. In a second interpretation, it means that a change in tariff design should not result in a significant change in the revenue recovered from any one class. And in a third interpretation, it means that all customers in a class should pay the same average tariff expressed in cents per kWh, $ per kW, or some combination thereof. Finally, there is the idealized theory of fairness and justice propounded by the late Harvard professor, John Rawls, regarded by many as the most significant philosopher of the twentieth century. One of the key elements of the theory is the Rawlsian concept of the "Difference Principle." Rawls argued that the greatest benefit should be accorded to the most

disadvantaged members of society.[1] Those who advocate lower tariffs for vulnerable customers are knowingly or unknowingly citing the ideas of Rawls.[2]

- Finally, the principle of "gradualism" suggests that tariffs should change gradually to reflect the long-term nature of investment in end-use electrical equipment, and the fact that such investment was made based on reasonable expectations about future tariffs. Gradualism avoids shocking and inconveniencing customers with sudden bill increases and simultaneously benefiting others with sudden bill decreases.

There are trade-offs between the three principles and policy makers have to recognize that it is not possible to devise a single "best" tariff structure for recovering residual costs that will score highly on all three principles. It is also necessary to recognise that different stakeholders may have different interpretations of the fairness principle, and therefore of how to score a particular tariff structure against this principle.

Drawing upon our survey of the literature and our survey of international practices, and recognizing the specific characteristics of the energy market in Australia, we developed five stylized tariff structures for recovering residual costs. These were developed using illustrative data on costs and customer load profiles. Finally, we evaluated the five against the three principles and reported the results.

If efficient pricing were the only relevant principle, residual costs would be recovered in the fixed charge because this would allow the variable charge (or demand charge) to be set at LRMC. However, a tariff with a very large fixed charge may be perceived as unfair, because (relative to current tariffs) customers with low consumption would pay more and customers with high consumption would pay less. One possible resolution might be to shift residual costs from the variable charge to the fixed charge gradually over a period of time in line with the gradualism principle. A second possibility might be to divide the household customer class into sub-classes according to load factor, so that residual costs could be allocated more fairly without large fixed charges. A third possibility might be to recover residual costs from other customer classes (not households) where the issue of fairness might carry less weight. Of course, the efficacy of such a proposal depends on the interpretation of "fairness" employed and may not be perceived as fair by any class of customers seeing a significant tariff increase as a result.

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[1] http://www.crf-usa.org/bill-of-rights-in-action/bria-23-3-c-justice-as-fairness-john-rawls-andhis-theory-of-justice. Also see: http://plato.stanford.edu/entries/rawls/.

[2] Harvard Professor Bill Hogan discusses an application of the Rawlsian definition of fairness while discussing dynamic pricing in http://www.hks.harvard.edu/fs/whogan/Hogan_Faruqui_043010.pdf. The final version of this paper appears in *The Electricity Journal*, 2010, vol. 23, issue 6, which contains several papers devoted to the ethics of dynamic pricing. In particular, Martin Bunzl, a philosophy professor at Rutgers University makes the counterargument that flat is fair. His argument is summarized on his blog. http://ccspp.blogspot.com/2010/04/is-flat-fair.html.

I. Introduction

The Australian Energy Market Commission is currently considering rule change proposals relating to the structure of distribution charges. We understand that there is a desire to move toward long run marginal cost (LRMC) pricing, but that LRMCs are lower than average costs and demand growth has slowed or turned negative. As a result, if all network tariffs were set at LRMC, the distribution network service providers (DNSPs) would not recover the total authorised cost of the network. The difference between total cost and the revenue recovered through LRMC tariffs is the "residual network cost". We were charged with evaluating alternative tariff designs for the recovery of residual network costs.

The scope of this report is limited to the recovery of residual network costs. In this report we are not addressing the closely-related topic of how to use estimates of LRMC to guide the design of the tariff, nor are we addressing how LRMC should be calculated. We are aware that the Australian DNSPs publish estimates of LRMC in their pricing proposals. In our report we have made use of some stylized figures to calculate hypothetical tariff structures in order to illustrate the impact of various options for recovering residual costs. In so doing we have not attempted to benchmark our stylized figures against actual estimates of LRMC for the Australian DNSPs. Rather we have been asked to assume a situation in which LRMC is significantly below average cost, such that there is a large amount of residual cost.

As the first task in this project, we carried out a review of the academic literature on electricity pricing. The results of our review are in section II, and an extended bibliography is in section V. We have also reviewed the structure of distribution tariffs in various international jurisdictions to derive insights on how residual costs might be recovered. The international case studies are in section III. In section IV we develop some stylized hypothetical tariff structures that might be used to recover residual network costs in Australia.

II.   Review of academic literature and industry expertise

While there is a vast literature on electricity pricing and an extensive literature on the estimation of marginal costs, the specialized literature on the pricing of distribution network services is considerably slimmer and that on recovering residual distribution costs when embedded costs exceed LRMC is virtually non-existent.

To augment the published literature, we reached out to two dozen academics, regulators, consumer advocates, consultants and utility practitioners that are located in the United States and abroad. We heard back from six academics, ten utility practitioners, one serving state regulator, one former state regulator, one former national regulator, one former consumer advocate and one consultant to consumer advocate. They shared with us their opinions on how to recover residual costs for distribution network services.

This section of the paper summarizes the learnings from the literature review and expert survey. A full bibliography appears in section V.

A.   PRINCIPLES OF TARIFF STRUCTURE

Professor James C. Bonbright is the most widely quoted expert on the subject. In his text on public utility tariffs (Bonbright, 1961 and 1988), he lays out ten principles for tariff design. These do not specifically focus on the pricing of distribution network services because when he was writing all utilities were vertically-integrated and distribution network services were not unbundled. Nevertheless, the ten principles noted below provide a framework within which distribution tariffs should be evaluated:

1. Effectiveness in yielding total revenue requirements, without encouraging undesirable over-investment or discouraging reliability and safety.

2. Revenue stability and predictability, with a minimum of unexpected changes that are seriously adverse to the utility companies.

3. Stability and predictability of the tariffs themselves, with a minimum of unexpected changes that are seriously adverse to utility customers.

4. Static efficiency, i.e., discouraging wasteful use of electricity in the aggregate as well as by time of use.

5. Reflection of all present and future private and social costs in the provision of electricity (i.e., the internalization of all externalities).

6. Fairness in the allocation of costs among customers so that equals are treated equally.

7. Avoidance of undue discrimination so as to avoid subsidising particular customer groups.

8. Dynamic efficiency in promoting innovation and responding to changing supply–demand patterns.

9. Simplicity, certainty, convenience of payment, economy in collection, comprehensibility, public acceptability, and feasibility of application.

10. Freedom from controversies as to proper interpretation.

In 2007, the Demand Response Research Center at the Lawrence Berkeley National Laboratory carried out a project to assist the two commissions in California deal with the state's pricing challenges. It published an Issues Paper in which the ten Bonbright principles were refreshed to deal with new issues that had emerged since Bonbright published his text (mostly dealing with the restructuring of the industry and the emergence of customer choice) and condensed into five principles[3]:

1. Economic efficiency in consumption and production.

2. Equity between customers and between the utility and the customers.

3. Revenue stability for the utility.

4. Bill stability for the customer.

5. Customer satisfaction.

In practice, economic efficiency is only one of five principles in tariff design, not the only one or even the dominant one. Equity, or treating different groups of customers fairly, and gradualism (i.e., avoiding sudden changes in the level of tariffs, to ensure revenue stability for the utility and bill stability for the customer) are equally important. And a new focus on customer satisfaction has emerged, since customers have become well versed in how to use energy wisely, both through investing in energy efficient equipment and by installing self-generation technologies, and how to choose their energy suppliers.

B.   DERIVATION OF PRINCIPLES FOR RECOVERY OF RESIDUAL COSTS

Based on the general principles of tariff structure enunciated above, the following three principles suggest themselves specifically for recovering residual costs. We recognize that there are trade-offs and therefore some associated tensions between the principles and judgement would have to be exercised in coming up with a final recommendation. This trade-off is likely to be different in different jurisdictions, reflecting different policy priorities and different statutory remits for the relevant regulatory agency.

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[3]   Faruqui, Hledik and Neenan (2007).

We also note that a fundamental tenet of regulation is that utilities are entitled to recover all prudently-incurred costs. Therefore the trade-off required to design a tariff to recover residual costs should not limit the utility's ability to recover all prudently incurred residual costs.

- The pricing of residual costs should not be inconsistent with the promotion of economic efficiency. This means that charges should be initially based on LRMC and adjusted to recover residual cost through Ramsey pricing, i.e., the inverse elasticity rule.

- The pricing of residual costs should not be inconsistent with the widely held concept of "fairness." While fairness is often not explicitly defined in a way that translates directly into tariff design, fairness may devolve into several sub-principles. Tariffs should not be changed so drastically that certain customers experience large bill increases in a short period of time while others experience large bill decreases. Tariffs should be designed to recover class revenues in proportion to the cost-of-service of each class as it has been traditionally allocated. And all customers in a class should pay the same average tariff.

- The pricing of residual costs should not be inconsistent with the principle of gradualism, meaning that tariffs should change gradually to avoid shocking and inconveniencing customers. The logic is that they have made investments in energy-using equipment conditional on a given set of tariffs and such equipment is long-lived. Additionally, habits take a long time to change.

C. ECONOMIC EFFICIENCY THROUGH MARGINAL COST PRICING

Economists have long argued that economic efficiency is best achieved through marginal cost pricing. Nelson (1964) pulls together the major contributions on the subject. Ralph Turvey is perhaps the most widely quoted authority on the subject. In various papers, Turvey (1964, 1968a, 1968b, 1977) lays out the importance of marginal cost pricing and describes alternative methods for computing marginal cost prices. While there is general agreement that marginal cost pricing works in theory, especially when it is applied to the pricing of electricity generation, there are differences of opinion about how marginal costs should be measured, how "long" is long, and how big should be the increment of demand over which the computations are carried out. The differences of opinion are particularly noticeable when it comes to the measurement of network costs, and these details become particularly important when demand is falling.

D. OPTIMAL DEPARTURES FROM MARGINAL COST PRICING

There is widespread recognition in the literature that capital intensive industries such as electric utilities are likely to face over or under-recovery of revenues if they move to unconstrained LRMC pricing. The question of how best to deviate from marginal costs has been preoccupying economists since Frank Ramsey wrote his paper on optimal taxation: Ramsey (1927). That paper proved to be seminal and was followed by several others that discussed what came to be known

as "Ramsey pricing." The literature on Ramsey pricing is summarized in Baumol and Bradford (1970).

Ramsey pricing involves price discrimination: charging different prices to different customer groups (or, in the case of multi-product or multi-service firms, charging different mark-ups over marginal cost on different products or services).[4] Customers who are price inelastic are charged a higher price than those who are price elastic, and thus more of the residual costs are recovered from customers who are price inelastic than from the customers with elastic demand. This has come to be known as the inverse elasticity rule.[5]

The logic behind Ramsey pricing is that any deviations from marginal cost pricing induce changes in the pattern of demand which are inefficient. Customers consume amounts that differ from the optimal amounts that they would consume if price was strictly at marginal cost. As a result, both consumer surplus and overall economic surplus are less than they would be if prices were set at marginal cost. By setting mark-ups inversely proportional to price elasticity, Ramsey pricing allows the firm to recover residual costs while minimising the deviations from optimal (i.e., based on marginal cost pricing) consumption patterns.

In electric utility pricing, the rule has often been used to set the *structure* of electricity prices. At the customer class level, Ramsey pricing would suggest that households pay a greater proportion of residual costs, and industrial customers a lesser portion, if the former are less price elastic and the latter are more price elastic. Within the residential class, it would also suggest that residual costs should be recovered more in fixed (or demand) charges and less in variable energy charges since the former are likely to be less price elastic than the latter.[6] However, Ramsey pricing has rarely been applied, at least not explicitly, for price discrimination across customers in the same class. The main reason is that equity considerations have stood in the way. It is often asserted that individuals who are relatively better-off are likely to show a higher elasticity for consuming certain goods such as electricity than individuals who are less well-off, because the better-off customers use some electricity for "luxuries", whereas the less well-off customers use electricity only for "essential" purposes.[7]

Train (1991) argues in the context of discussing alternative modes of public transit in the San Francisco Bay Area, either the AC Transit bus or the BART train: "Ramsey prices, if

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[4]   It is sometimes called third-degree price discrimination to distinguish it from the case where each customer would pay a different price based on their willingness to pay. In that case, the monopolist would expropriate all consumer surplus.

[5]   See Crew and Kleindorfer (1979) for a derivation.

[6]   Consistent with this notion, practice in Great Britain before privatisation used to be that residual costs were recovered in fixed charges (see section III.B).

[7]   It is unclear how well this assertion has been tested empirically. Some authors, such as Reiss and White (2002) argue that low-income customers are likely to show higher price elasticity for electricity use.

implemented, would require that lower-income riders of the bus subsidize the higher-income riders of the BART. From an equity perspective, this arrangement would be unsuitable."

However, Train does suggest an approach whereby Ramsey pricing might be made politically acceptable. He says that Ramsey prices maximize the total economic surplus without considering the distribution of the surplus and in most cases, such as the mass transit discussed above, it may well seem inequitable. If the regulator can find a way to redistribute the expanded surplus, then the inequity would go away. However, the regulator cannot always effectively implement a redistribution of surplus. In these cases, Train suggests that "the regulator needs to consider the equity impacts of Ramsey prices when deciding whether to implement them."

In fact, arguably the inverse of Ramsey pricing has been used in some jurisdictions with lower prices being charged to low income customers, who are perceived to have lower price elasticities since their low levels of consumption are focused on necessities such as lighting and cooking.[8] The residual revenue is recovered by charging higher prices to other customers.[9]

In closing, we want to draw attention to an important question that arises in the practical implementation of Ramsey pricing: do customers respond to price in a way that is effectively captured by the models traditionally used by economists? Ramsey pricing assumes that customers respond to (marginal) prices. It is sometimes suggested that customers are relatively unaware of (and therefore cannot respond to) the price schedules in a utility's tariff structure, and that other considerations such as the change in monthly bill are more important in driving consumption patterns. If the tariff structure is anything other than a one-part volumetric tariff where the price is constant regardless of consumption, then a change in marginal prices will result in a different change in monthly bills.

If the tariff is structured as a two-part design, where the first part is a fixed charge and the second part is a uniform (flat) volumetric charge, customers are likely to understand the prices in the tariff structure and the issue should not pose any meaningful complications for the application of Ramsey pricing. But if the second part has a block tariff structure, and there are multiple blocks, then customers are less likely to know what the marginal price is. [10] In that case, modifications to the traditional Ramsey formula might need to be made.

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8   For example, in California low income customers are eligible for the CARE program under which they buy electricity at substantially discounted tariffs. The loss in revenue is recovered from all other customers. The customers fill out a form that comes with their electric bill. In the form, they state that their income falls into the low income categories specified on the form. No additional proof is required. It is self-stated by the customer.

http://www.cpuc.ca.gov/PUC/energy/Low+Income/care.htm.

9   Baiman (2001) calls this progressive social pricing and argues that when a social welfare function is defined as including both equity and efficiency as parameters, that it is the more general case of the inverse elasticity rule associated with Ramsey pricing.

10   Ito (2012).

We note that this is largely an empirical issue that is likely to be more significant in some jurisdictions than others. We also note that in Australia the DNSP tariff is "mediated" by the retailers who pay the DNSP charges but do not necessarily pass them on in the same structure to their customers. Currently, the only significant evidence on this comes from California's where complex multi-part volumetric tariffs are poorly presented to the customer and confusion reigns in the customer's mind.

E.   NONLINEAR PRICING

As noted by Willig (1978) and Brown and Sibley (1986), for capital-intensive industries economic welfare can be improved by moving from linear (flat or one-part) pricing (whether based on marginal costs or involving the Ramsey-correction) to nonlinear pricing (involving multiple parts). Joskow (2007) and Wilson (1993) summarize the literature on the subject.

Nonlinear pricing for electricity distribution would typically consist of a fixed charge and a volumetric charge which could be flat or have a block tariff structure (inclining or declining). The fixed charge would be designed to recover the fixed costs of generation, transmission and distribution while the volumetric charge would be designed to recover the variable costs of generation, mostly fuel, and possibly variable transmission and distribution costs (losses). If the appropriate metering infrastructure is in place, the volumetric charge could have a time-varying character which could either be static (e.g., two or three period time-of-use tariffs) or dynamic (e.g., critical peak pricing or real time pricing).[11]

In further refinements, the fixed charge can be subdivided into a charge that covers metering and customer care costs and is strictly fixed (e.g., a monthly charge per connection) and a demand charge per kW that recovers the cost of the network. This would lead to a three-part tariff,

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[11]   Several papers are listed in the bibliography on the topic of time-varying energy charges. See Faruqui and Sergici (2013) for a survey of pricing experiments and full-scale programs that feature time-varying energy charges. The theoretical case for time-varying charges and an exhaustive review of the literature appears in Crew and Kleindorfer (1976) and also in Crew, Fernando and Kleindorfer (1995). The first known reference to time-varying rates in the economics literature dates back to Clark (1911). He also hinted at the use of "demand meters" and, if they were not available, at using estimates of "connected load." Noting that electricity could not be stored, he made a case for time-of-use rates, citing a report of the St. Louis Public Service Commission on Rates for Electric Light & Power. He stated: "If a customer agreed not to use current at the time of day, about five o'clock usually, he would on the cause theory, be freed from all responsibility for the capital costs of the central plant (though not of the distribution system)." Lyndon (1923) expanded upon the concept of connected load as a proxy for maximum demand by saying it could be based on the number of openings (i.e., sockets) in a house and distinguished between active and inactive openings. He opined that one could "consider every opening in a house as a 50-watt load and one-half the total openings as the maximum load which each dwelling will impose on the system." He then proceeded to make a case for a declining block volumetric rate, saying the first block would recover the costs associated with the maximum demand that the customer would impose on the system and the second block would recover the cost of energy.

which has been widely practiced around the globe for medium and large commercial and industrial customers. It has a long history, going back to Hopkinson (1892). In his presidential address to the Junior Engineering Society, he said: "The ideal method of charge then is a fixed charge per quarter proportioned to the greatest rate of supply the consumer will ever take, and a charge by meter for the actual consumption."[12] As Crew and Kleindorfer (1979) put it: "Maximum-demand tariffs, which were to become so popular in the industry over the years were born. Their original intent was apparently to come to terms with the peak-load problem to the extent that they aimed to improve utilization or load factor."

The main challenge in applying the three-part tariff to residential customers has been the lack of demand metering capability for residential customers. However, it has been deployed for years in some European countries including France and Italy.[13] Elsewhere, for residential customers the fixed charge collects the costs of metering and customer care and the volumetric charge collects all or a large proportion of the demand-related costs.[14] The demand-related charge is based upon the load factor of the group, adjusted for the system diversity factor.[15]

F.   EQUITY AND DISTRIBUTIONAL IMPACTS

As noted earlier, the process of designing tariffs is fraught with the need to make trade-offs between competing objectives. Economic efficiency, which receives the top honours in the economists' toolbox when it comes to pricing, does not often occupy a similar position in the regulators' toolbox. That top honour is reserved for a broadly conceived notion of equity or fairness.

Of course, there is a recognition that the onus of addressing equity issues, especially protecting the well-being of vulnerable customers, devolves on the elected government officials and not on the appointed regulatory bodies. However, in practice regulatory bodies in several countries have felt the weight of public opinion on their shoulders and have taken remedial steps to protect vulnerable customers.

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[12]   The Hopkinson tariff contains an explicit demand charge, for example: demand charge = $2.50 per month per kW of maximum demand in the month, plus an energy charge of 5 cents per kWh per month. It was followed soon thereafter by a tariff developed by Arthur Wright. The Wright tariff achieves the same objectives without requiring the measurement of demand. It uses a declining block rate structure where the charge for energy might be 10 cents per kWh for the first 50 hours of use and 5 cents for the next 50 hours of use and so on. "Given any Hopkinson rate structure, one can always develop a Wright rate structure which will produce identical bills." See Neufeld (1987) for additional discussion.

[13]   See below, section III.C.

[14]   In some jurisdictions a proportion of the network costs is recovered in the fixed charge (see section III.B).

[15]   See Chapter 4 of Crew and Kleindorfer (1979) for additional details.

William Vickrey, a Nobel laureate in Economics, wrote in 1971 about the difficulties in basing prices on marginal costs. He said that the main difficulty with marginal cost pricing is "likely to be not just mechanical or economic, but political." He felt that people shared the medieval notion of a just price as an ethical norm, and that prices that varied according to the circumstances of the moment were intrinsically evil. He opined:

"The free market has often enough been condemned as a snare and a delusion, but if indeed prices have failed to perform their function in the context of modern industrial society, it may be not because the free market will not work, but because it has not been effectively tried."[16]

Vickrey proposed setting the usage charge equal to marginal costs and reconciling the revenue imbalance by a residual cost collection.[17]

The regulatory tensions between these objectives have been recognized for a long time, going back to the writings of the British writer Dalton (1938):

"There has never been any lack of interest in the subject of electricity tariffs. Like all charges upon the consumer, they are an unfailing source of annoyance to those who pay, and of argument in those who levy them. In fact, so great is the heat aroused whenever they are discussed at institutions or in the technical press, that it has been suggested that there should be a "close season" for tariff discussions. Nor does this discussion exaggerate their importance. There is general agreement that appropriate tariffs are essential to any rapid development of electricity supply, and there is complete disagreement as to what constitutes an appropriate tariff."

As argued by Faruqui (2010–11) in the context of electricity pricing, from an economic efficiency standpoint, all customers should face cost-based tariffs so they can make optimal consumption decisions. If society as a whole wants to protect vulnerable consumers, it can institute other mechanisms such as "energy stamps," akin to "food stamps" to make sure they have the funds to meet their essential energy needs. Governments would have to tap into their general revenue fund to make this happen. We understand that Australian governments, such as the NSW Government, have established community service obligations which include items such as emergency energy payment vouchers, rebates for low income households and rebates for people on life-support equipment. In the UK, all senior citizens are given an annual payment of between

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[16] Vickrey, William, "Responsive pricing of public utility services," *Bell Journal of Economics and Management Science*, 2, 1971, pp. 337–346.

[17] Vickrey's first study on efficient electricity pricing dates back to 1939 and was funded by the Twentieth Century Fund. He is regarded as the father of congestion pricing, a concept he first proposed in 1952 for the New York City subway system. He recommended that fares be increased in peak times and in high-traffic sections and be lowered in others. Elected officials considered it risky, and the technology was not ready. Later, he made a similar proposal for road pricing. Vickrey considered time-of-day pricing as a classic application of market forces to balance supply and demand. Those who are able can shift their schedules to cheaper hours, reducing congestion, air pollution and energy use. See http://www.vtpi.org/vickrey.htm.

one hundred and three hundred pounds to assist them with their winter heating needs.[18] Such payments generally fall in the category of income supplements and would appear to be more economically efficient than discounting prices.

Similar concerns have arisen in the pricing of natural gas, as noted by Borenstein and Davis (2012) in their study of natural gas pricing: "The reality is that whenever policymakers can influence prices there is a temptation to use these prices to accomplish distributional goals. This is despite the fact that economists generally view optimal tariff design as separate from redistribution, particularly when there are broader redistributive tools in place such as the income tax. Striking a balance between these two objectives is perhaps the biggest challenge faced by utility regulators."

These concerns notwithstanding, regulators in many countries have often given a lot of weight to distributional concerns. In many cases, this has meant excluding vulnerable customers from price increases. Vulnerable customers may be low income customers, customers on fixed incomes (such as old age pensioners) or customers who require electrically-powered medical equipment. It has often been difficult to identify such customers and the process has often involved self-selection (as in California's CARE[19] program) or the use of a proxy such as usage. Low use consumers are often interpreted as low income customers even though the empirical evidence on that correlation is decidedly weak.[20]

Nevertheless, this argument is presented when the case is made for inclining block tariffs. It is argued that the first block is below average costs to protect the well-being of the vulnerable customers. It is also argued that the last block is above average costs to promote energy efficiency. In British Columbia, when inclining block tariffs were introduced, the main driver was the need for a tariff increase, since LRMCs were found to exceed average costs. It was decided to impose the entire tariff increase on the second tier and to leave prices in the first tier unchanged. The presumption was that the first tier represented usage that was necessary to ensure a suitable lifestyle. Decades earlier, when California introduced its lifeline tariffs in 1975, the presumption was that the first tier represented minimum usage for the necessities of a basic lifestyle.

Even Lewis (1941) argues that the imposing the same fixed charge on all customers is often viewed as discriminating against small users. He notes that "the small consumer of electricity may be small because he is using it only for lighting, while the large may be using it for heat, power, or other purposes for which the demand is more elastic than for lighting." And so he states that to avoid discriminating heavily against small consumers, "undertakings sometimes

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[18]   See: https://www.gov.uk/winter-fuel-payment/what-youll-get.

[19]   California Alternate Rates for Energy (http://www.cpuc.ca.gov/PUC/energy/Low+Income/care.htm).

[20]   See, e.g., the evidence cited in Borenstein and Davis (2012). Similar lack of correlation has been cited in rate cases involving the Commonwealth Edison Company of Illinois or Pacific Gas & Electric Company of California.

have a different fixed charge for each consumer, varying according to the rateable value of his house, the number of rooms, or similar index. This has indeed the advantage that the fixed charge can be made to increase so rapidly [across customers] that in effect larger consumers are made to pay higher average prices per unit than smaller consumers."

He then goes on say that another approach is to exempt smaller users from a fixed charge but to offer them a flat volumetric charge where the price is slightly higher than the volumetric charge in the two-part tariff that is offered to all other users. Another option is to let the size of the first block may vary from consumer to consumer.[21]

Lewis reminds us that the two-part tariff, applied uniformly across all customers, is prone to run into political difficulties. He cites the opposition from the Parliamentary Secretary to the Board of Trade who said in 1933:

"I am not attempting to justify the exclusion of the minimum charge from the Bill on any ground of logic or technicality. I am doing it entirely on the political argument that the Government are not prepared to face the opposition that would necessarily come from people in scattered places amounting to millions in total who would never understand the reasons behind a clause of this kind."[22]

Regulators have also put a lot of weight on doing studies that allocate the total requirement among classes of customers using one of many different methods. Once the class revenue allocations have been dene, the onus on tariff design is to ensure that they recover the revenue requirement of that class. This is often carried out using one of many demand allocation methods. As laid out in an Opinion offered by the Federal Energy Regulatory Commission in the United States:

"Demand allocation refers to the method of apportioning fixed capacity costs among customer classes. The Commission typically uses a coincident peak method to allocate demand costs, in which demand costs are allocated based on the customer class' demand at the time of (coincident with) the system peak demand. The coincident peak may be based, for example, on a single peak month (1 CP), the average of three peak months (3 CP), or the average of peaks in twelve months (12 CP). A company that has a relatively flat demand curve throughout the year would typically allocate demand on a 12 CP basis, which assumes that a utility's demand is relatively constant throughout all twelve months of the year. A summer (or winter) peaking company would more

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[21] These cases are discussed further in Brown and Sibley (1986) where the discussion as posed as one in which the small user will select the volumetric tariff and the large user will select the two-part tariff. This scenario would dominate the one in which only a single two-part tariff is offered and will improve economic well-being for society as a whole.

[22] Joint Committee of the House of Lords and House of Commons on Gas Prices (H.L., 24, 91, H.C. 110), 1937, para. 16.

typically allocate demand on a 3 CP basis, which assumes demand will peak during the three peak usage months."[23]

G.   THE PRACTICE OF DISTRIBUTION PRICING

As a practical matter, given the absence of demand metering for household customers in many jurisdictions, distribution network tariffs use a two-part design (fixed and kWh-based). Even where household customers have smart meters capable of measuring demand, tariffs rarely include a demand charge.[24] The first part, the fixed charge, however, is usually small and does not recover the full cost of investing in, operating and maintaining the grid. It often only recovers the cost of metering and customer care, or a small proportion of the total network costs. While almost the entire costs of the distribution network are fixed relative to the number of kWh distributed, often less than a fifth of distribution revenue is recovered through the fixed charge. In some cases, the fixed charge may recover less than a tenth of the fixed costs.[25]

A new study by EPRI (2014) indicates that, for the US as a whole, the average customer's all-inclusive monthly bill amounts to $110, corresponding to a usage of 982 kWh per month. Of this amount, it is estimated that $70 is for generation charges, $10 for transmission charges and $30 for distribution charges. EPRI estimates that variable energy costs amount to $59 a month and fixed capacity costs to $51 a month. In other words, even if a customer does not consume any energy but wishes to remain connected to the grid, that customer would need to pay $51 for that service if the tariff structure reflected the structure of costs.

Yet the average fixed charge for investor-owned utilities is around $8 per month[26] with the number for municipal utilities and cooperatives being higher.[27] The remainder is recovered through the volumetric charge. When demand growth slows down, or turns negative, this results in insufficient revenue recovery.

In a few cases, as mentioned earlier, demand charges are deployed that vary with the size of the customer's connection[28] or with actual peak demand.[29] A new report that has just been released by the Grattan Institute in Australia makes a strong case for instituting demand charges.[30]

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[23]   FERC (2008).

[24]   Italy is an exception (see section III.C), though here the tariff is three-part, with the volumetric charge recovering most of the costs.

[25]   For the 14 DNSPs in Great Britain, for example, between 7% and 20% of costs for households are recovered in fixed charges, and 80% to 93% are recovered in kWh charges.

[26]   In many cases, the charge is zero or virtually zero. In some cases, it is around $15-20 a month.

[27]   For the investor-owned segment, the $51 a month capacity charge is comprised of $14 a month for generation capacity and $37 a month for transmission and distribution capacity.

[28]   See section III.C.

[29]   For example, Arizona Public Service *Rate Schedule ECT-2 Residential Service Time-of-Use with Demand Charge Combined Advantage 7pm-Noon.*

III. Examples of tariff structures in other jurisdictions

A. INTRODUCTION

The problem of structuring electricity distribution tariffs is universal, although the nature of the challenge facing the designer of tariff structures depends to an extent on factors such as industry structure, cost trends, and the type of metering technology available. Jurisdictions in Australia have very high proportions of households with PV generation relative to utilities in other jurisdictions, and other jurisdictions with high PV penetration have very different industry structures. To an extent, therefore, pricing problem facing utilities and regulators in Australia may be more severe than in other jurisdictions. Nevertheless, it is useful to study the structure of electricity distribution tariffs in other places as a possible source of ideas for dealing the problems that appear to be unique to Australia but are not that unique.

After surveying the international experience with tariff structures, we have decided to highlight the following cases in this report:

- Great Britain, where, although distribution network tariffs are relatively low, significant efforts have been made recently to redesign the structure of tariffs;

- Italy, which with France is one of the few countries where demand charges are applied to households, and where the network tariff has been adjusted to reflect equity concerns; and

- US jurisdictions, where utilities are often required to estimate LRMC and where residual cost recovery has raised equity concerns.

B. GREAT BRITAIN

There are 14 DNSPs in Great Britain. Since 2011 all of the networks have employed the same methodology for determining the structure of distribution tariffs.[31] The common methodology (known as the Common Distribution Charging Model or CDCM)[32] is a type of long-run incremental cost methodology, where tariffs are determined to recover the costs associated with

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Continued from previous page

[30] Wood and Carter (2014). The report also discusses the need to move to the volumetric portion of the rate toward a critical-peak pricing rate, citing the considerable experimental evidence that is available on the subject. See Faruqui and Sergici (2013) for an updated survey of how customers respond to CPP (and other time-varying rates).

[31] *Electricity distribution structure of charges: the common distribution charging methodology at lower voltages*, Ofgem (November 2009).

[32] *CDCM model user manual*, energy networks association (February 2013). Note that the CDCM model, as well as versions of the model populated with the cost data for each of the 14 networks is publicly available. See footnotes to Table 1.

a 500 MW increment of demand.[33] For low voltage customers, including households, the tariff is two-part. The fixed (or "standing") charge is set to recover the household customers' share of the forward-looking costs of the low-voltage (LV) network.[34] The household customers' share of the higher-voltage network costs are recovered in the volumetric (/kWh) charge. Our understanding is that while the CDCM is relatively new, the approach whereby low-voltage network costs are recovered in the standing charge and higher voltage costs are recovered in a volumetric charge has not changed in some time. When Ofgem approved the CDCM, it indicated that this split did not seem to be principles-based and that further work would be required to refine it. However, our understanding is that no changes have yet been implemented. While we have not found any explanation of the thinking behind this approach, the approach would be consistent with the following reasoning:

- if LV network costs are principally determined by the number of customers (rather than demand or throughput), it makes sense to recover those costs equally from each customer in a fixed charge;
- as demand and throughput on the LV network increases, network reinforcement at higher voltage levels is required;
- the need for reinforcement at higher voltage levels is driven mostly by peak demand; and
- in the absence of demand metering, if there is a correlation between kWh and peak demand, it makes sense to recover these costs in a kWh charge; and
- even if there is weak correlation between kWh and peak demand for individual customers, kWh rather than fixed charges may be perceived as more fair.

The results of this method for allocating costs to household customers are that the majority of the network costs paid by households are in the energy or variable charge, presumably because the costs of the network are predominantly at higher voltages. Table 1 shows that for household customers between 7% and 20% of network costs are recovered in fixed charges, and 80% to 93% are recovered in kWh charges.

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[33] There are various methodologies for calculating forward-looking "marginal" network costs, some of which are labelled "incremental" and some "marginal". The distinction between these various methodologies is beyond the scope of this paper, and we use the term "LRMC" to refer to such methodologies generally.

[34] Note that in Great Britain the costs of meters and meter reading are not part of the DNSP revenue requirement. The "low voltage" network means any assets below 1 kV.

Table 1

Distribution Charges and Annual Average Customer Bills

	Variable Rate (p/kWh)	Fixed Charge (p/customer/ day)	Annual Averages					
			Consumption (kWh)	Variable Costs (£)	Fixed Costs (£)	Total Costs (£)	% Variable Costs	% Fixed Costs
Electricity North West								
Electricity North West	3.038	1.940	3,200	97.22	7.08	104.30	93.2%	6.8%
Northern Powergrid								
Northern Powergrid (Northeast)	2.792	4.830	3,200	89.34	17.63	106.97	83.5%	16.5%
Northern Powergrid (Yorkshire)	2.263	4.710	3,200	72.42	17.19	89.61	80.8%	19.2%
Scottish Power Distribution								
SP Distribution	2.283	5.040	3,200	73.06	18.40	91.45	79.9%	20.1%
SP Manweb	4.114	3.730	3,200	131.65	13.61	145.26	90.6%	9.4%
SSE Power Distribution								
Scottish Hydro Electric Power Distribution	3.710	6.810	3,200	118.72	24.86	143.58	82.7%	17.3%
Southern Electric Power Distribution	2.397	2.950	3,200	76.70	10.77	87.47	87.7%	12.3%
UK Power Networks								
Eastern Power Networks	2.053	4.310	3,200	65.70	15.73	81.43	80.7%	19.3%
London Power Networks	2.117	3.990	3,200	67.74	14.56	82.31	82.3%	17.7%
South Eastern Power	2.617	3.990	3,200	83.74	14.56	98.31	85.2%	14.8%
Western Power Distribution								
Western Power Distribution (East Midlands)	2.266	1.470	3,200	72.51	5.37	77.88	93.1%	6.9%
Western Power Distribution (West Midlands)	2.356	2.270	3,200	75.39	8.29	83.68	90.1%	9.9%
Western Power Distribution (South Wales)	3.470	2.720	3,200	111.04	9.93	120.97	91.8%	8.2%
Western Power Distribution (South West)	3.456	2.950	3,200	110.59	10.77	121.36	91.1%	8.9%

Sources: Common Distribution Charging Model for each DNO.
Average annual consumption is assumed to be 3,200 kWh (Ofgem decision on typical domestic consumption, September 13, 2013).
To access the CDCM for each DNO (besides the Western Power Distribution DNOs), visit
http://www.energynetworks.org/electricity/regulation/distribution-charges.html and click on the link for each DNO at the bottom of the webpage. For example, click on "Electricity North West" and then click on the link called "ENWL - CDCM Model 102 - 01Apr14" to download the CDCM spreadsheet. The Western Power Distribution CDCMs can be downloaded under the "CDCM Models" section online here: http://www.westernpower.co.uk/About-us/Use-of-system-charges/Use-of-System-Charges.aspx.

Under the CDCM, LRMC charges are similarly determined for the other customer groups and voltage levels. Because these charges are forward-looking and based on incremental costs, the aggregate revenue collected by means of charges equal to incremental costs will not be equal to the total costs of the network. Table 2 shows the difference between total cost and revenue recovered from LRMC charges. The range is from recovering less than half the required revenue to recovering about 11% more than the total costs.

Table 2

Total Residual Network Costs (£m)

	CDCM Target Revenue	Net Revenue before Matching	Shortfall/ Surplus	Shortfall/Surplus as % of Target Revenue
Electricity North West				
Electricity North West	516.9	355.7	161.2	31.2%
Northern Powergrid				
Northern Powergrid (Northeast)	330.0	178.4	151.6	45.9%
Northern Powergrid (Yorkshire)	401.3	225.5	175.8	43.8%
Scottish Power Distribution				
SP Distribution	350.7	247.8	102.9	29.3%
SP Manweb	409.1	248.7	160.5	39.2%
SSE Power Distribution				
Scottish Hydro Electric Power Distribution	260.4	139.1	121.3	46.6%
Southern Electric Power Distribution	563.3	398.6	164.7	29.2%
UK Power Networks				
Eastern Power Networks	564.0	549.7	14.2	2.5%
London Power Networks	475.5	528.7	-53.2	-11.2%
South Eastern Power	411.1	317.1	94.0	22.9%
Western Power Distribution				
Western Power Distribution (East Midlands)	448.8	327.7	121.1	27.0%
Western Power Distribution (West Midlands)	469.6	293.1	176.5	37.6%
Western Power Distribution (South Wales)	264.6	134.6	130.0	49.1%
Western Power Distribution (South West)	358.9	173.0	185.9	51.8%

Sources: Common Distribution Charging Model (CDCM) for each DNO.

Because of the difference between revenues at LRMC tariffs and total costs, a "scaling" factor needs to be applied to the tariffs in order to recover residual costs. In Great Britain, transmission network charges are paid by the DNSPs, and are therefore a component of the total DNSP costs to be recovered from users of the distribution network. The transmission network costs are recovered from the DNSPs as a demand charge, and these costs are flowed through the CDCM in the same way as the costs of high-voltage distribution network assets. Under the CDCM, the methodology for recovering the residual costs is to replace the actual transmission network demand charge with a different figure chosen so that, once it is flowed through the regular methodology, the adjusted distribution tariffs recover the required total costs. Because the transmission charge is at the highest voltage level of the network, the adder appears in the variable (per kWh) charge for household customers.[35] Thus, under the CDCM, residual costs for

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[35] As explained above, for low voltage customers, the fixed charge recovers the LRMC of the low voltage network, and the variable charge recovers the LRMC of the higher voltage parts of the network. Thus, for household customers, the transmission network charge adder recovering residual costs flows through into the variable (per kWh) charge but leaves the fixed charge unchanged.

household customers are recovered in the kWh charge only, with the fixed charge recovering strictly only the LRMC of the low-voltage network. As the residual costs can be a significant fraction of total costs, the scaling of the variable charge for households in order to recover the residual costs can result in significant increases. Table 3 shows that the increase ranges from −12% to +130%, with five of the fourteen DNSPs having increases of around 100%.

Table 3

% Increase in Variable Charge for Households due to Residual Cost Recovery

	Variable Rate (p/kWh)			Scaler as % of LRMC
	Before Scaling	Scaler	After Scaling	
	[a]	[b]	[c] = [a] + [b]	
Electricity North West				
Electricity North West	2.037	1.001	3.038	49.2%
Northern Powergrid				
Northern Powergrid (Northeast)	1.401	1.391	2.792	99.3%
Northern Powergrid (Yorkshire)	1.163	1.101	2.263	94.7%
Scottish Power Distribution				
SP Distribution	1.506	0.777	2.283	51.6%
SP Manweb	2.414	1.700	4.114	70.4%
SSE Power Distribution				
Scottish Hydro Electric Power Distribution	1.768	1.942	3.710	109.8%
Southern Electric Power Distribution	1.607	0.790	2.397	49.2%
UK Power Networks				
Eastern Power Networks	1.992	0.060	2.053	3.0%
London Power Networks	2.408	-0.290	2.117	-12.1%
South Eastern Power	1.943	0.674	2.617	34.7%
Western Power Distribution				
Western Power Distribution (East Midlands)	1.591	0.675	2.266	42.4%
Western Power Distribution (West Midlands)	1.353	1.003	2.356	74.1%
Western Power Distribution (South Wales)	1.602	1.868	3.470	116.5%
Western Power Distribution (South West)	1.505	1.952	3.456	129.7%

Sources: Common Distribution Charging Model (CDCM) for each DNO.

As mentioned above, the methodology for determining which costs flow through to fixed and variable charges for the recovery of LRMC has remained unchanged for some time and was not altered as a result of the initiative to develop a common charging methodology across the industry. However, the mechanism for recovering residual costs was altered in that process. Traditionally, residual costs had been recovered in fixed charges only. We have not seen an

explicit explanation of why residual costs were recovered in this way, although one possible reason is that before independent economic regulation was instituted and before privatisation, the revenue that the industry collected was not strictly connected to underlying costs, and could change significantly from one year to the next. Recovering residual costs in the fixed charge would minimise the impact of revenue variations on demand (and hence costs).[36]

While the traditional approach had been to recover residual costs through adjusting fixed charges, during the development of the CDCM, a second alternative was proposed in which each element of the network capital cost would be scaled[37] in order to match total revenue with the authorised revenue requirement. This approach was rejected because it would mean that none of the resulting tariffs or tariff components would be cost-based. Unfortunately, it is not clear from the various decision documents we have reviewed why the approach of collecting residual costs in the fixed charge was rejected.

C. ITALY[38]

The structure of distribution network tariffs in Italy has two unusual and interesting features: first, the distribution network tariff has a demand charge for household customers, with the demand charge levied on the "size" of the connection to the network (i.e., the peak power that can be drawn through the meter); and second, there is a defined "ideal" tariff structure towards which tariffs are supposed to evolve over time (though this process appears not to have begun yet), but actual tariffs are different from the ideal in order to protect low-income customers.[39]

The Italian distribution network tariff is three-part: a fixed charge, a demand charge, and an energy charge. The demand charge is levied on the "size" of the connection to the network. The customer can choose the size of the connection, which then acts as a limit on the power (kW) that can be demanded at any point in time. Our understanding is that this approach has been

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[36] This is equivalent to a Ramsey pricing argument, since the objective is to minimise changes in consumption in both cases.

[37] In LRMC models it is usual to convert capital costs to an annual cost through an "annuity rate", which in principle would be equal to the DNSP's cost of capital. The proposal during the development of the CDCM was to vary the annuity rate until the revenues matched.

[38] According to an industry expert who was interviewed for this study, all residential customers in France pay a demand charge because that is "a fair and easier way to manage the networks." The practice dates back to the 1950s. Customers choose a maximum demand level (demand above the chosen level is automatically cut off), and the fixed charge depends on the demand level chosen. For example, a 3kW connection costs about $75 per year, 9kW costs about $160 per year and 15kW costs about $285/year. The fixed charge for customers with time-of-use energy charges also vary with the chosen maximum demand level. (Tariffs are at https://particuliers.edf.com/offres-d-energie/electricite-47378.html?gcl).

[39] The tariff is not explicitly linked to income, but a higher tariff is charged to homes that are not owner-occupied and to connections with maximum offtake greater than 3 kW. In addition, there may be an assumption that the demand charge results in a correlation between bills and income.

used for a long time in Italy and predates the arrival of smart meters. All households in Italy now have smart meters, and one of the functionalities of the smart meter is that it can limit the maximum power delivered to the house. That maximum can be remotely adjusted if the customer requests a change to a different maximum capacity. Before smart meters were installed, similar tariff structures were used, but a technician had to visit the house in order to change the maximum power.

For the "ideal" tariff, the fixed charge covers the cost of metering and some other customer-related costs, and the demand charge and variable charges together cover the cost of the network. We were not able to discover the precise definition of how total network costs are split between demand and variable charges.

No customers currently pay the "ideal" tariff. Rather, customers are divided into two groups: those with off-takes of 3kW or below where the home is owner-occupied, and those with off-takes above 3kW plus homes that are not owner-occupied. The tariff for the second group is the same as the ideal tariff, except that there is an inclining-block structure added to the variable charge where all of the blocks are above cost (the fixed and demand charges remain cost-based). The tariff for the first group has a similar inclining block structure for the variable charge, except that the first few blocks are below cost. In addition, both the fixed and demand charges for the first group are below cost. Table 4 shows the elements of the tariff for a low-use customer (where the variable charges are all in the first block), and Table 5 shows the flat variable charge structure for the ideal tariff (D1) and in the inclining block structure for tariffs for low usage (D2) and high usage or homes that are not owner-occupied (D3).

Table 4
D1, D2, and D3 Tariffs
For Low Use Customers (< 1,800 kWh/yr)

	Fixed Charge (€)	Demand Charge (€/kW)	Variable Charge (€/kWh)
D1	20.7	15.6	0.016
D2	6.1	5.7	0.005
D3	20.7	15.6	0.025

Sources:
D1, D2, and D3 tariffs from
http://www.autorita.energia.it/allegati/docs/11/199-11TITtab_new.xls.

Table 5

Variable Charge (€/kWh)

Annual Consumption	D1	D2	D3
0 to 900 kWh	0.016	0.005	0.025
901 to 1,800 kWh	0.016	0.005	0.025
1,801 to 2,640 kWh	0.016	0.042	0.042
2,641 to 3,540 kWh	0.016	0.082	0.082
3,541 to 4,440 kWh	0.016	0.082	0.082
4,441 kWh and up	0.016	0.124	0.124

Sources:
D1, D2, and D3 tariffs from
http://www.autorita.energia.it/allegati/docs/11/199-
11TITtab_new.xls.

The results of this system are that customers with the smallest consumption pay tariffs that are below cost (and, correspondingly, customers consuming more pay above cost). Furthermore, the inclining block structure provides an incentive to improve energy efficiency. Finally, there are some additional costs associated with having a larger connection. Table 6 shows total bill, the split between fixed, demand and variable charges, and the average tariff (total bill divided by total consumption).

Table 6

Distribution Charges for Various Levels of Consumption

	Fixed Charge (€)	Demand Charge (€)	Variable Charge (€)	Total	% Fixed	% Demand	% Variable	Average Rate (€/kWh)
1.5 kW, 1,800 kWh	6.1	8.6	8.7	23.4	26.1%	36.7%	37.2%	0.013
3 kW, 3,000 kWh	6.1	17.2	73.2	96.5	6.3%	17.8%	75.9%	0.032
4.5 kW, 4,250 kWh	20.7	70.1	211.0	301.8	6.9%	23.2%	69.9%	0.071
6 kW, 10,000 kWh	20.7	93.5	917.6	1,031.7	2.0%	9.1%	88.9%	0.103

Sources and Notes:
D1, D2, and D3 tariffs from http://www.autorita.energia.it/allegati/docs/11/199-11TITtab_new.xls.
Bills with a max demand less than or equal to 3 kW are calculated using the D2 tariff. All other bills are calculated using the D3 tariff.

Table 6 shows that bills (and average tariff) increase significantly for larger users. While the demand charge accounts for some of this increase, the largest impact is from the inclining block variable charge.

The D2 and D3 tariffs that customers pay are designed to over- or under-recover revenue relative to the "ideal" D1 tariff. Table 7 shows the impact of charging customers at D2 or D3 relative to D1. Moving horizontally across the rows of Table 7 shows the impact of the inclining block variable charges, whereas moving down the columns shows the impact of the demand charge.

Table 7

Difference Between Actual Annual Bills and Bills Based on "Ideal" Tariff (€)

Annual Consumption (kWh)	500	1,400	2,150	3,000	4,250	10,000
Max Demand (kW)						
1.5	-35.2	-45.6	-41.4	-5.5	76.0	687.9
3	-49.9	-60.4	-56.2	-20.3	61.2	673.2
4.5	4.1	11.5	23.7	59.6	141.0	753.0
6	4.1	11.5	23.7	59.6	141.0	753.0

Difference Between Actual Annual Bills and Bills Based on "Ideal" Tariff (% over Ideal)

Annual Consumption (kWh)	500	1,400	2,150	3,000	4,250	10,000
Max Demand (kW)						
1.5	-67.2%	-68.0%	-52.1%	-5.9%	66.6%	329.7%
3	-66.0%	-66.8%	-54.6%	-17.4%	44.5%	290.1%
4.5	4.2%	10.1%	18.8%	42.5%	87.7%	294.8%
6	3.4%	8.4%	15.8%	36.4%	76.6%	270.1%

D. US JURISDICTIONS

Many utilities in the US estimate marginal costs to inform a variety of pricing decisions. However, it is relatively unusual for marginal cost studies to be used directly to set distribution tariffs. In many cases, customers are charged a "bundled" tariff because retail competition in electricity is relatively unusual in the US. Furthermore, US regulators tend to put significant weight on avoiding "rate shock" (large tariff increases), and it is common to use the structure of existing tariffs as a starting point for determining new tariffs, rather than a fresh analysis of tariff structure based on first principles. Nevertheless, there are a few jurisdictions where unbundled distribution tariffs are set. We document below the approach to structuring distribution tariffs in Texas and Massachusetts. We also briefly discuss the recovery of "transition costs", which is an interesting example because it represents a large amount of additional cost that had to be recovered through tariffs, in principle posing the same challenges as the recovery of residual network costs (such as the need to balance fairness with efficient pricing).

1. Texas

Much of Texas has retail competition, and the equivalent of DNSPs provide only a "delivery" service. In Texas the issue of recovering residual costs has not been an issue since the state continues to experience robust sales growth and there is no net energy metering. Tariffs for household customers have a fixed charge that recovers metering and certain "account" costs,

with the costs of the network entirely recovered through a volumetric charge. The fixed charges are relatively low, around $3 to $6 per customer per month. Volumetric charges are $0.02/kWh to $0.03/kWh. Since the average customer in Texas uses more than 1,000 kWh per month, bills are around $300–400 per customer per year, with just under 20% of the bill consisting of a fixed charge.[40] The tariff for one of the Texas DNSPs, Oncor, is shown in Table 8.

Table 8

Oncor Residential Rate

Metering Charge ($/month)	2.280
Customer Charge ($/month)	0.780
System Charge ($/kWh)	0.019

Source:
Oncor Tariff for Retail Delivery Service
Residential Service.

2. Massachusetts

In Massachusetts DNSPs typically prepare a marginal cost study as evidence in support of the proposed structure of distribution tariffs. In principle, the LRMC should be recovered in the volumetric charge, and residual costs should be recovered in the fixed charge. In practice, a number of other considerations come into play in order to balance the objective of efficient tariffs with fairness. The steps below relate to a regulatory proceeding that determined distribution tariffs for a gas utility, but the same principles would apply to the determination of electricity distribution tariffs.

In the case of the Boston Gas company,[41] the company conducted a marginal cost study to determine the marginal costs for adding an additional customer to its system, and similarly the marginal cost for an additional unit of peak throughput. The company has two-part tariffs (a fixed monthly charge and a variable energy charge), with a two-block declining block structure. The company's marginal cost study suggested that significant residual costs would need to be recovered from domestic customers: around $15/month for customers without space heating, and around $30/month for customers with space heating. These figures would imply, for winter months, about 90% fixed costs and 10% variable costs for a median customer without space heating, and about equal fixed and variable costs for a median customer with space heating.

The regulator did not accept fixed charges based on the company's marginal cost study (nor the lower fixed charges the company proposed). Instead, the company was directed to recover some

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[40] *Comparison of Utilities' Generic T&D Rates*, Public Utilities Commission of Texas, March 2014.

[41] *Petition of Boston Gas Company d/b/a KeySpan Energy Delivery New England, pursuant to General Laws Chapter 164, § 94, and 220 C.M.R. § 5.00 et seq. for a General Increase in Gas Rates*, D.T.E. 03-40 (Massachusetts Department of Public Utilities, October 31, 2003).

of the residual costs in the fixed charge, and the balance in the first block of a two-block declining volumetric tariff. The regulator determined fixed charges of $9.50 per month and $12.00 per month (rather than the $15 and $30 figures required to recover residual costs). The balance of the residual costs was to be recovered through a volumetric charge on volumes up to the consumption of the median customer. All customers consuming more than the median pay a volumetric charge in the second block equal to LRMC.[42]

The process by which the regulator arrived at this outcome is not entirely clear, but the regulator did cite the following principles:

- Residual costs are to be allocated to the customer class which "caused" the cost (i.e., original cost, allocated in proportion to the "use" that the class makes of the various assets).
- No customer class is to see a tariff increase more than 125% of the average increase.
- For any customer class that would otherwise go past the cap, the increase beyond the cap is allocated first to any customer classes that would otherwise see a tariff decrease, sufficient that tariffs for that class do not decrease.
- Any remaining increase is allocated equally across the remaining classes.
- A separate re-allocation is done to reduce tariffs for low-income customers.[43]

3. Transition cost recovery

In the late 1990s, several jurisdictions in the US restructured their wholesale markets and removed the monopoly of the existing utilities over the generation sector. This process led to "restructuring costs" as independent power producers were able to enter the market with new plant that were able to generate at prices below the costs of the existing generators (often because the new generators were gas-fired). Utilities could not recover the costs of their existing fleet in the market, but were allowed to recover the difference between embedded cost and market price from their retail customers by levying "restructuring" charges to recover these costs.

In California, restructuring costs totaled approximately $21-25 billion[44] and were recovered through a non-bypassable Competitive Transition Charge ("CTC"). CTCs were implemented as volumetric bill charges.[45] The charges were applied to all consumer classes, with a few exceptions such as state agricultural and water projects.[46] The CPUC "will fairly allocate the CTC to avoid

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[42] *Ibid.*, pp. 378-388.

[43] *Ibid.*, pp. 384-5.

[44] Michaels, R.J. "Stranded in Sacramento: California Tries Legislating Electrical Competition." *Regulation,* Volume 20, Issue 2, Spring 1997, p. 52.

[45] "Provisions of AB 1890." Published by the EIA.
      http://www.eia.gov/electricity/policies/legislation/california/assemblybill.html.

[46] "AB 1890 Assembly Bill – Bill Analysis." http://www.leginfo.ca.gov/pub/95-96/bill/asm/ab_1851-1900/ab_1890_cfa_960905_114137_asm_floor.html.

cost shifting among classes by using current cost allocation principles."[47] The transition costs were recovered by allocating charges among all customer classes based on "an equal percentage of marginal cost (EPMC) methodology."[48]

Pennsylvania collected approximately $11 billion for restructuring costs,[49] through a variable CTC.[50] The CTC is non-bypassable and is applied to all customers, and the charges were designed to be collected for a period lasting for up to 9 years. The transition costs are "allocated to customer classes in a manner that does not shift interclass or intraclass costs and maintains consistency with the allocation methodology for utility production plant accepted by the commission in the electric utility's most recent base rate proceeding."[51]

The common theme in these proceedings was that that existing tariff structures were to be maintained. As a result, restructuring costs have been recovered in large part through volumetric tariffs.

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[47]   California Public Utilities Commission (CPUC), D9512063, Section 5.
       http://www.cpuc.ca.gov/PUC/energy/Retail+Electric+Markets+and+Finance/Electric+Markets/Historic
       al+Information/D9512063/D9512063_sec5.htm.
[48]   California Public Utilities Commission (CPUC), D9512063, Section 5.
       http://www.cpuc.ca.gov/PUC/energy/Retail+Electric+Markets+and+Finance/Electric+Markets/Historic
       al+Information/D9512063/D9512063_sec5.htm.
[49]   "Electricity Restructuring and Rate Caps." From the Commonwealth Foundation, August 2009.
[50]   See, for example, Appendix IV-3 to the PECO Energy Company Tariff effective January 1, 2003.
       http://www.hvacc.net/pdf/peco/rate_gs_correcta.pdf.
[51]   The General Assembly of Pennsylvania §2808.
       http://www.legis.state.pa.us/cfdocs/legis/LI/consCheck.cfm?txtType=HTM&ttl=66&div=0&chpt=28&sc
       tn=8&subsctn=0.

IV. Hypothetical stylized tariff structures that could be used in Australia

As noted earlier, Australia is considering a move toward LRMC for the pricing of distribution network services. However, LRMC's are lower than existing tariffs and the issue of recovering the difference—residual costs—has arisen. Several alternatives exist. In order to examine the choices, we have to first lay out some methodology.

A. METHODOLOGY

In order to illustrate some stylized tariff structures that could be used to recover residual costs, we have constructed a simple tariff design model. This is constructed around a simplified set of parameters which describe network usage across a small number of prototypical customers, and describe hypothetical network costs. Our goal in doing this is to illustrate the broad features of different tariff structures, such as the split of total costs between fixed and variable, and the contribution to the recovery of residual costs of high and low usage customers. We are not intending to represent the actual costs or tariffs of any specific DNSP. The methodology is general enough to be applied to specific DNSPs once the requisite data has been obtained. In such an application, it may be better to work with a load research sample consisting of hundreds or possibly thousands of customers.

For our purposes we need to assume values for the following parameters:

- the LRMC for incremental demand from household customers, expressed in $/kW/year;
- the total annual consumption (kWh/year) and the peak demand (kW) for an average household;
- the total network cost; and
- the fixed charge ($/customer/year).

LRMC has a "natural unit" of $/kW or $/kW/year because LRMC represents the rate at which costs change as demand is added. It is therefore expressed in $/kW or $/kW/year. We make the common assumption that there are essentially no DNSP costs which increase as kWh increase with peak demand held constant. Residual costs do not have the same "natural units" because residual costs are simply that—residual costs in $/year that are left over after revenues raised from charging LRMC tariffs are subtracted from total costs. Residual costs, by definition, do not change with demand or anything else. It can therefore be confusing to express residual costs in $/kWh, because this implies that each kWh should be charged the same contribution towards residual costs. While this may be one possible charging option, it is not the only one (see below). Nevertheless, it is convenient to express total and residual costs in $/kWh because otherwise the dollar figures are necessarily specific to a particular network. However, in expressing total and residual costs in $/kWh it is important to be clear as to what quantity of kWh are being used to calculate these figures. For the purposes of this report, we simply divide the total network cost by the total throughput to obtain an average $/kWh figure. We assume that total network costs are

approximately $0.15/kWh. This figure is similar to numbers in a recent AEMC report on electricity prices.[52]

We present some stylized calculations starting from an average consumption of 6,500 kWh/year, which we understand to be the average consumption in NSW.[53] We also assume a corresponding peak demand of 4 kW. These figures correspond to an annual bill for network services of $1,000 for a customer with the average 6,500 kWh annual consumption.

We are aware that the Australian DNSPs publish estimates of LRMC in their pricing proposals. In preparing stylized figures to calculate hypothetical tariff structures in order to illustrate the impact of various options for recovering residual costs, we have been asked to assume a situation in which LRMC is significantly below average cost, such that there is a large amount of residual cost needing to be recovered. We have assumed an LRMC of $75/kW/year. We did not choose this figure on the basis of reviewing existing estimates of LRMC for the DNSPs but rather chose it to ensure (as shown below) that there would be a significant amount of residual cost, that being the focus on our report.

We assume a fixed charge of $150/customer/year,[54] together with other parameters for an average customer as shown in Table 9. We assume that the fixed charge covers customer-related costs (such as a proportion of the low-voltage network costs that is built out to serve each customer), such that the fixed charge of $150/customer/year represents recovery of additional costs incurred to serve each customer, but does not contribute to recovering the residual cost of the network.[55] Table 9 also shows that, based on these parameters, pricing at LRMC plus a cost-based fixed charge fails to recover a significant proportion of total costs. If the variable charge were increased to recover total network costs, the variable charge would be $0.131/kWh, significantly greater than the $0.046/kWh LRMC-based variable charge.[56]

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[52] Table 5.2 of *2013 Residential Electricity Price Trends* gives $0.16–0.17/kWh as the network costs for residential customers in NSW.

[53] *2013 Residential Electricity Price Trends*, AEMC (December 2013) gives 6,500 kWh as the medium consumption level for NSW (Table 5.1).

[54] This figure is approximately equal to Ausgrid's fixed charge for household customers. *Ausgrid Network Pricing Proposal*, May 2014, gives a figure of $0.40/customer/day in Table 3d.

[55] It is possible that the fixed charge is set above the level that would recover customer-related costs on an incremental basis (we note, for example, that fixed charges in many overseas jurisdictions are below this level). If this is the case, residual costs may be larger than what we show in this report, and some residual costs may already be being recovered in fixed charges.

[56] It would not be difficult to construct examples with an alternative set of assumptions tailored to specific DNSPs, to better represent their individual circumstances.

Table 9

Parameters for Hypothetical Average Customer

Annual consumption (kWh)	[1]	6,500
Peak Demand (kW)	[2]	4.0
LRMC ($/kW/yr)	[3]	75
LRMC ($/kWh)	[4]	0.046
Total Cost ($/kWh)	[5]	0.154
Fixed Charge ($/yr)	[6]	150
Total Cost per Customer ($/yr)	[7]	1,000
Revenue per Customer at LRMC ($/yr)	[8]	450
Residual Cost as % of Total Cost	[9]	55%
Variable Charge to Recover Total Costs ($/kWh)	[10]	0.131
Residual Cost as % of LRMC	[11]	183%

Sources and Notes:
[1] AEMC report "2013 Residential Electricity Price Trends".
[2] Assumption.
[3] Assumption.
[4] = [3] x [2] / [1].
[5] Assumption (consistent with prior table).
[6] Assumption.
[7] = [5] x [1].
[8] = [6] + [1] x [4].
[9] = 1 - [8] / [7].
[10] = ([7] - [6]) / [1].
[11] = [10] / [4] - 1.

Table 9 (by design) shows significant residual network costs. On a per kWh basis for the average household customer, the LRMC is about $0.05/kWh. However, a variable charge of about $0.13/kWh is needed to ensure full cost recovery if all of the residual costs are recovered in the variable charge. LRMC-based charges recover only about 45% of the total cost, leaving a residual cost of 55%.[57] If all of the residual costs are recovered in the variable charge, the variable charge would be close to three times the LRMC.

Based on the tariff structure and stylized charges outlined above, we have calculated the total bill for network services for six prototypical customers representing a wide range of levels of consumption and peak demand. Table 10 shows bills of $540 to $1,460 per year, for consumption ranging from 3,000 kWh to 10,000 kWh per year. The calculations in Table 10 are designed to be

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[57] Assuming, as discussed above, that the fixed charge of $150/customer/year is not recovering any residual cost.

a stylized representation of a "flat" network tariff. All customers are assumed to pay the same variable kWh charge. The variable charge in Table 10 is equal to the variable charge calculated in Table 9 to ensure that, for the average customer, the total bill is equal to the average cost.[58] The tariff and bills shown in Table 10 indicate a split between fixed and variable charges that is similar to current DNSP tariffs in Australia (for example, for a customer using 6,500 kWh/year variable charges account for 85% of the total bill). We have included two demand levels (4 kW and 8 kW) in order to test the impact of tariff structures that include demand charges. We have also assumed a hypothetical distribution of customer counts, shown in the first column of Table 10, so that we can calculate an average bill across the six consumption levels weighted by customer count. The weights are chosen subject to the constraint that the weighted average bill is $1,000/customer/year.

Table 10
Network Bills for Six Stylized Levels of Consumption

			Charges:	Fixed	Demand	Variable
Tariff components				150.00	0.00	0.131
Units				$/year	$/kW/year	$/kWh
Customers (% of total)	Annual consumption (kWh)	Peak demand (kW)	Total annual bill ($)	Components of the bill ($)		
10%	3,000	4	542.31	150.00	-	392.31
30%	6,500	4	1,000.00	150.00	-	850.00
10%	10,000	4	1,457.69	150.00	-	1,307.69
10%	3,000	8	542.31	150.00	-	392.31
30%	6,500	8	1,000.00	150.00	-	850.00
10%	10,000	8	1,457.69	150.00	-	1,307.69
Average revenue per customer ($/yr)			1,000.00			

Notes:
Based on parameters in Table 9.
100% of residual costs recovered in the variable charge.

The six consumption levels in Table 10 were chosen to span a range of possible consumption patterns. For example, the first row in the table might correspond to a small house or an apartment without central air-conditioning; the sixth row might correspond to a house with central air-conditioning; and the fourth row might correspond to a house with both central air-conditioning and a large solar PV installation. We emphasize that the consumption levels are stylized and are not based on any actual consumption data. They are intended to illustrate the possible impact of alternative tariff structures for recovering residual network costs. Numbers

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[58] Effectively, we are assuming that the total cost of the network divided by the total number of customers is $1,000 per year, as shown in Table 9.

that better match the current parameters for individual DNSPs can be constructed using our methodology.

It is also important to note that in this analysis we have not taken into account any adjustments that customers might make to their consumption patterns in response to price changes, i.e., we have not introduced price elasticity estimates into the analysis. While such adjustments would happen (and could be significant, given the large changes in tariff components illustrated here), estimating them is beyond the scope of this study. In future work, it may be useful to allow for such elasticity effects in determining the final set of tariffs for recovery of residual costs.[59]

Under the pricing arrangements shown in Table 10, we assume that all of the residual network costs are recovered in the volumetric charge. We understand that this is a reasonable representation of current pricing arrangements. Although some DNSPs have recently increased the fixed charge, we understand that the variable charge continues to account for the bulk of the revenue recovered from household customers.

In the sections which follow we present some stylized alternative tariff structures for recovering residual network costs.

B.   APPROACHES

1.   Postage-stamp pricing

This would be the simplest option in which the residual costs would be recovered by raising the volumetric charge above LRMC by the same amount for all customers. There are several ways of accomplishing this. As noted by Chamberlin and Seiden (1993/94): "[T]he simplest of these solutions is the equal proportions rule, where the prices to all customers in a class deviate from marginal costs by the same proportion." Kim and Baughman (1997) further elaborate that the revenue shortfall could be recovered in one of several ways. For example, it could be added or multiplied into the LRMC to recover the residual cost. Or it could be applied just to those hours where the distribution network is likely to experience reliability issues. In all cases, to the extent that price elasticity exists, an adjustment would have to be made that works into the revenue adjustment an allowance for customer response to price changes.[60]

Our understanding is that this option is similar to the current charging arrangements, shown in stylized form in Table 10 above.

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[59]   There is precedence for introducing elasticity estimates in developing new rates. For example, Xcel Energy in Colorado introduced inclining block rates a few years ago and factored in the price-induced changes in consumption that would be induced by such rates in determining the rates. In the US, such an approach is called revenue repression.

[60]   This method coincides with Ramsey pricing if price elasticities are equal across all customer segments and fixed charges are not to be increased.

2. Ramsey pricing without changing fixed charges

Ramsey pricing recovers the difference between LRMC and average cost in inverse proportion to elasticity. Thus, residual costs are recovered disproportionately from inelastic consumption. If large fixed charges are to be avoided, and demand meters are absent, this would recover the residual costs only by raising the volumetric charge, but disproportionately across customers. It would raise prices by a greater proportionate amount for customers with inelastic demands and a lesser amount for customers with elastic demands. That way the deviations in quantities demanded would be the smallest compared to the allocation that is optimal from an efficiency standpoint (i.e., based on LRMC).

The challenge with implementing such an approach is in identifying those customers (or units of consumption) which are more elastic and those which are less. It is commonly assumed that customers who consume relatively little electricity show less price elasticity. However, there is limited empirical evidence on relative magnitudes. There is a presumption that low use customers are less price responsive and high use customers are more price responsive.

Table 12 shows a stylized example where the volumetric charge is increased above LRMC for all customers, but the increase is greater for customers with smaller consumption. This approach essentially yields a declining block tariff. The parameters of the declining block tariff are shown in Table 11.

Table 11
Declining Blocks: Option A

	Lower bound (kWh/yr)	Upper bound (kWh/yr)	Variable charge ($/kWh)
Block 1	0	4,000	0.162
Block 2	4,000	8,000	0.091
Block 3	8,000	--	0.069

Notes:
Block widths assumed at 4,000 and 8,000 kWh.
Block 3 rate at 50% uplift over LRMC;
Block 1 uplift at 5:1 relative to block 3;
Block 2 rate to keep average bills at $1,000/yr.

The charges shown in Table 11 were chosen to keep the average bill at $1,000/year. The third block has an "uplift" over LRMC of 50%, and the first block has an uplift of 250%.

Table 12 shows the corresponding bills (note that the last column shows the average energy charge paid by each of the six customer types, which is equal to the charge in the first block for customers 1 and 4, but is a weighted average for the other four customer types which have consumption in more than one block).

Table 12

Customer Bills under Ramsey Pricing without Changing Fixed Charges: Option A

		Charges:	Fixed	Demand		Variable
Tariff components			150.00	0.00		
Units			$/year	$/kW/year		

Customers (% of total)	Annual consumption (kWh)	Peak demand (kW)	Total annual bill ($)	Components of the bill ($)		Average energy charge ($/kWh)
10%	3,000	4	634.62	150.00	0.00	484.62	0.162
30%	6,500	4	1,022.74	150.00	0.00	872.74	0.134
10%	10,000	4	1,297.16	150.00	0.00	1147.16	0.115
10%	3,000	8	634.62	150.00	0.00	484.62	0.162
30%	6,500	8	1,022.74	150.00	0.00	872.74	0.134
10%	10,000	8	1,297.16	150.00	0.00	1147.16	0.115
Average revenue per customer ($/yr)			1,000.00			

Notes:
Based on parameters in Table 9.
100% of residual costs recovered in the variable charge, but residual cost recovery weighted to the lower blocks.

Declining block tariffs are a form of non-linear pricing. They can be introduced with or without a fixed charge. The declining block tariff structure is appropriate if LRMC is less than average cost.[61]

The volumetric tariffs in Table 12 are not calculated to reflect estimates of price elasticity but rather conform with the common assumption that elasticity is smaller for customers with lower consumption. While this is intended simply to be a stylized example, we note that the last block includes an uplift of 50% above LRMC, and that there is a 5:1 ratio between the uplift in the first and last blocks. In this example, residual cost recovery is causing very large departures from marginal cost pricing.

Once again, we have not included the ex post price elasticity effects in these computations.

In Table 13 we show the impact of this stylized tariff structure on average tariffs and bills, for our six prototypical customer types. The changes shown in Table 13 are relative to our stylized version of the current pricing arrangements shown in Table 10 above.

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[61] Chamberlin and Seiden (1993/94) show through numerical simulation that declining block tariffs are efficient if the marginal cost of large customers is less than the marginal cost of serving small customers. They also argue that inclining block tariffs would be more efficient if the opposite relationship holds between the marginal cost of serving large and small customers.

Table 13

Ramsey Pricing without Large Fixed Charges: Bill Impacts

Annual consumption (kWh)	Peak demand (kW)	Average tariff ($/kWh)	Bill change ($/yr)	Bill change (%)
3,000	4	0.21	92.31	17%
6,500	4	0.16	22.74	2%
10,000	4	0.13	-160.54	-11%
3,000	8	0.21	92.31	17%
6,500	8	0.16	22.74	2%
10,000	8	0.13	-160.54	-11%

We noted above that Table 12 implies significant deviations from LRMC pricing for all levels of consumption (all kWh). An alternative method for choosing the parameters of the declining block tariff would be to set the third block equal to LRMC. A second set of declining blocks are shown in Table 14. The ratio between the uplift in the first and second blocks is 4:1.

Table 14

Declining Blocks: Option B

	Lower bound (kWh/yr)	Upper bound (kWh/yr)	Variable charge ($/kWh)
Block 1	0	4,000	0.175
Block 2	4,000	8,000	0.072
Block 3	8,000	--	0.046

Notes:
Block widths assumed at 4,000 and 8,000 kWh.
Block 3 rate at 0% uplift over LRMC;
Block 1 uplift at 5:1 relative to block 2;
Block 2 rate to keep average bills at $1,000/yr.

The bills and bill increases corresponding to this second set of declining blocks are shown in Table 15 and Table 16.

Table 15

Customer Bills under Ramsey Pricing without Changing Fixed Charges: Option B

			Charges:	Fixed	Demand		Variable
Tariff components				150.00	0.00		
Units				$/year	$/kW/year		

Customers (%	Annual	Peak demand	Total annual	Components of the bill ($)			Average
10%	3,000	4	675.79	150.00	0.00	525.79	0.175
30%	6,500	4	1,030.99	150.00	0.00	880.99	0.136
10%	10,000	4	1,231.26	150.00	0.00	1081.26	0.108
10%	3,000	8	675.79	150.00	0.00	525.79	0.175
30%	6,500	8	1,030.99	150.00	0.00	880.99	0.136
10%	10,000	8	1,231.26	150.00	0.00	1081.26	0.108
Average revenue per customer ($/yr)			1,000.00				

Based on parameters in Table 9.
100% of residual costs recovered in the variable charge, but residual cost recovery weighted to the lower blocks.

Table 16

Ramsey Pricing without Large Fixed Charges: Bill Impacts, Option B

Annual	Peak demand (kW)	Average tariff ($/kWh)	Bill change ($/yr)	Bill change (%)
3,000	4	0.23	133.48	25%
6,500	4	0.16	30.99	3%
10,000	4	0.12	-226.44	-16%
3,000	8	0.23	133.48	25%
6,500	8	0.16	30.99	3%
10,000	8	0.12	-226.44	-16%

We note that these options result in customers with the lowest consumption paying the highest average price. Relative to the status quo, these options produce large bill increases for customers who consume the least, some of whom are likely to be vulnerable or low-income. Furthermore, the options we have shown are directionally consistent with Ramsey pricing principles and efficient pricing, but to be implemented in practice would require actual elasticity estimates for different groups of customers, and also a way to identify those customers (it is likely that the level of consumption is at best an imperfect proxy for variations in elasticity across customers).

One of our utility experts noted that "Ramsey pricing was always an interesting postulate and nothing more." Another commented that it was feasible to apply at the customer class level but almost impossible to apply within a class. There is some evidence to suggest that price elasticity is proportional to income, being lower (in absolute terms) for low use customers and higher for high use customers. However, there are at least three difficulties: first, the evidence is not conclusive that price elasticity in fact varies predictably with income; second, there would likely

be some serious practical difficulties with setting discriminatory tariffs according to income; and third, such tariffs would be regressive.[62]

3. Gradually raise the fixed charge for all customers

In this approach, the residual costs would be initially recovered through the volumetric charge, but, perhaps over a period of several years, the fixed charge would be raised and the volumetric charge lowered. This argument can be found in Berry (2000) who argues that the usage-sensitive tariff element should be set equal to marginal cost and the non-usage sensitive element should be set to ensure that revenues are recovered.

This option would see large increases in the fixed charge. One way to mitigate the impact on customers of sudden changes and conform to the principle of gradualism would be to phase in the increases in the fixed charges and accordingly reduce the decreases in the volumetric charges, with the ultimate goal of setting the volumetric charge equal to LRMC and thereby achieving the desired result in terms of economic efficiency. Table 17 and Table 18 illustrate this approach, showing the results of the first year of a six-year phase-in.

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[62] A contrarian viewpoint on Ramsey pricing is provided by Baiman (2001) who argues that the traditional view of Ramsey pricing, i.e., the inverse elasticity rule, is a special case of a general theorem which he calls progressive social pricing theorem. In his "immanent critique" of neoclassical economics, Baiman argues that the inverse elasticity rule will not be equity neutral and that it may cause regressive static social welfare losses which are both unfair and inefficient. He thus proposes the use of progressive social price regulation, in which prices are moved in direct proportion to the price elasticity of demand rather than in inverse proportion.

Table 17

Phase in Increased Fixed Charges over 6 Years: Year 1

			Charges:	Fixed	Demand	Variable
Tariff components				250.00	0.00	0.115
Units				$/year	$/kW/year	$/kWh

Customers (% of total)	Annual consumption (kWh)	Peak demand (kW)	Total annual bill ($)	Components of the bill ($)		
10%	3,000	4	596.15	250.00	0.00	346.15
30%	6,500	4	1,000.00	250.00	0.00	750.00
10%	10,000	4	1,403.85	250.00	0.00	1,153.85
10%	3,000	8	596.15	250.00	0.00	346.15
30%	6,500	8	1,000.00	250.00	0.00	750.00
10%	10,000	8	1,403.85	250.00	0.00	1,153.85
Average revenue per customer ($/yr)			1,000.00			

Notes:
Fixed charge increased by $100/yr to recover some residual costs; balance of residual cost remains in the variable charge.

Table 18

Phase in Increased Fixed Charges: Bill Impacts in Year 1

Annual consumption (kWh)	Peak demand (kW)	Average tariff ($/kWh)	Bill change ($/yr)	Bill change (%)
3,000	4	0.20	53.85	10%
6,500	4	0.15	0.00	0%
10,000	4	0.14	-53.85	-4%
3,000	8	0.20	53.85	10%
6,500	8	0.15	0.00	0%
10,000	8	0.14	-53.85	-4%

The corresponding second year of the phase-in is shown in Table 19 and Table 20. Once the phase in is complete there would be significant increases for low-use customers, and customers with the largest usage would see bills go down.

Table 19

Phase in Increased Fixed Charges over 6 Years: Year 2

			Charges:	Fixed	Demand	Variable
Tariff components				350.00	0.00	0.100
Units				$/year	$/kW/year	$/kWh

Customers (% of total)	Annual consumption (kWh)	Peak demand (kW)	Total annual bill ($)	Components of the bill ($)		
10%	3,000	4	650.00	350.00	0.00	300.00
30%	6,500	4	1,000.00	350.00	0.00	650.00
10%	10,000	4	1,350.00	350.00	0.00	1000.00
10%	3,000	8	650.00	350.00	0.00	300.00
30%	6,500	8	1,000.00	350.00	0.00	650.00
10%	10,000	8	1,350.00	350.00	0.00	1000.00
Average revenue per customer ($/yr)			1,000.00			

Notes:
Fixed charge further increased by $100/yr to recover additional residual costs; balance of residual cost remains in the variable charge.

Table 20

Phase in Increased Fixed Charges: Cumulative Bill Impacts by Year 2

Annual consumption (kWh)	Peak demand (kW)	Average tariff ($/kWh)	Bill change ($/yr)	Bill change (%)
3,000	4	0.22	107.69	20%
6,500	4	0.15	0.00	0%
10,000	4	0.13	-107.69	-7%
3,000	8	0.22	107.69	20%
6,500	8	0.15	0.00	0%
10,000	8	0.13	-107.69	-7%

4.   Raise the fixed charge but exempt low-income customers

An option that may be more acceptable to the general public is to set the volumetric charge at LRMC and to recover the residual cost by raising the fixed charge but exclude low income customers from the higher fixed charge. Thus, the entire residual cost would be recovered from all other consumers. A prerequisite for this approach is that a way would be found for identifying low income customers. In California, where about a third of the customers are on a low income discounted tariff called CARE, low income customers simply identify themselves by filling out a form that states their eligibility for the program, by referring to a table of qualifying income levels which is provided to them. In Australia, mechanisms that are used to identify vulnerable

customers to whom disburse emergency energy assistance funds and rebates are provided could be used to identify low income customers.

In a variation of this idea, customers would be segmented into size categories. These could be based on average monthly kWh consumption, size of the house, number of bedrooms in the house, its rated property value, whether it is attached or detached and so on. Higher fixed charges would be levied on "larger" customers and lower fixed charges on "smaller" customers, however larger and smaller are defined. Additionally, customers who are of pensionable age could be considered eligible for the lower fixed charge; so also any customers who use electricity to power life-sustaining medical equipment. Such a tariff has been approved in Bermuda.[63] The utility estimated that the fixed costs of serving customers were $41 a month. It has instituted a seven-tier fixed charge which has an average value of some $30 a month (so that about one quarter of the fixed costs are recovered in volumetric charges); the charge for the smallest users is around $20 a month and the charge for the highest users is around $75 a month.

Table 21 and Table 22 illustrate the approach of recovering residual costs through fixed charges, while excluding vulnerable customers. For convenience we assume that vulnerable customers are those consuming the least electricity. Note that in the absence of demand metering or other information, it might be difficult to distinguish between a vulnerable customer and a non-vulnerable customer with PV, since both are likely to have similar low kWh consumption. The stylized tariff structure in Table 21 has been structured so that the bill for the customers with the smallest consumption stays the same (the fixed charge is increased enough to offset the decrease in the variable charge, as shown in Table 22). The variable charge is set equal to LRMC, and the fixed charge is increased to ensure recovery of total revenues including residual costs.

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[63]   Presentation by Walter M. Higgins III at the Utility Executive Course in Idaho, June 24th, 2014.

Table 21

Increase Fixed Charges, No Bill Change for Small Users

			Charges:	Fixed	Demand	Variable
Tariff components				774.04	0.00	0.046
Units				$/year	$/kW/year	$/kWh

Customers (% of total)	Annual consumption (kWh)	Peak demand (kW)	Total annual bill ($)	Components of the bill ($)		
10%	3,000	4	542.31	403.85	0.00	138.46
30%	6,500	4	1,074.04	774.04	0.00	300.00
10%	10,000	4	1,235.58	774.04	0.00	461.54
10%	3,000	8	542.31	403.85	0.00	138.46
30%	6,500	8	1,074.04	774.04	0.00	300.00
10%	10,000	8	1,235.58	774.04	0.00	461.54
Average revenue per customer ($/yr)			1,000.00			

Notes:
Variable charge at LRMC.
Fixed charge for small users set to ensure no bill impact from status quo.
Fixed charge for other users set to ensurey revenue recovery.

Table 22

Increase Fixed Charges, No Bill Change for Small Users: Bill Impacts

Annual consumption (kWh)	Peak demand (kW)	Average tariff ($/kWh)	Bill change ($/yr)	Bill change (%)
3,000	4	0.18	0.00	0%
6,500	4	0.17	74.04	7%
10,000	4	0.12	-222.12	-15%
3,000	8	0.18	0.00	0%
6,500	8	0.17	74.04	7%
10,000	8	0.12	-222.12	-15%

5. Install smart meters and introduce demand charges

Once smart meters have been deployed, a three-part tariff could be instituted for all customers.[64] The demand charge could be based on actual peak consumption, consumption at system peak, the size of the connection, or some combination of these. Energy charges would be lowered accordingly to ensure that there is no over-recovery of revenues. Over time, since most (or all) of

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[64]   This recommendation is echoed in the report by Wood and Carter (2014).

the network costs are independent of kWh distributed, the energy charges would become much smaller (or zero) and revenue recovery would be mostly achieved through fixed and demand charges.[65]

One utility expert who works with a distribution utility in a market with competitive retailers noted that 98 percent of distribution costs were fixed (with the balance of 2 percent being associated with taxes) while another, who also works with a distribution utility in a market with competitive retailers, indicated that 100 percent of distribution costs were fixed. The first expert indicated that they expected that smart meters would be in place by 2018 and once that came to pass, they would strongly push for a cost-based three-part tariff. The second expert indicated that smart meters were going to be in place by 2015 and they would then start pushing for a two-part tariff for distribution services. The first part would be a fixed monthly charge and the second part would be a demand charge. There would be no volumetric charge for distribution services since distribution costs do not vary with the amount of energy being supplied to the customers. Both utilities are required also to offer standard retail services and such utilities are sometimes called integrated distribution utilities. They would offer tariffs for the standard retail service but this would appear separately from the tariffs for distribution and transmission services on the customer's bill.

Even without smart meters, estimates of demand charges could be levied based on the size of the customer's connection, or based on a proxy for peak demand. Peak demand could be imputed using load research studies, or estimated on the basis of observable characteristics such as the size of the house. As noted earlier, there is precedent for doing this. Early in the industry's history, fixed charges were used as a substitute for the customer's imputed demand and based on the number of bedrooms and the value of the property.[66]

One of our experts noted that demand charges allow recovery of fixed costs much better than any other mechanism and their magnitude can be determined by referring to the planning criteria of design day maximum demands. If desired, demand meters can be deployed for homes above a certain size, as has been done in Arizona.

Demand charges would have to be implemented gradually. In one scenario, once the LRMCs have been estimated, the demand charge would be set so it captures a portion of the LRMC and the volumetric charge captures the balance. The customer charge would be set to recover the residual cost. Alternatively, the demand charge could be set to recover all of the LRMC, with the recovery of residual costs split between the customer charge and the volumetric charge.

It may be necessary to exclude vulnerable customers, however categorized, from any tariff increase impacts. Alternatively, the tariff increases could be phased in over time, to minimize

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[65] A time-of-use energy charge is another alternative which can be set up to be equivalent to a demand charge.

[66] Lewis (1941) discusses this point.

adverse bill impacts on any customers. Alternatively, adverse impacts on vulnerable customers could be buffered through Governmental assistance programs.

Table 23 and Table 24 show the results of a stylized tariff with a demand charge set at LRMC and residual costs recovered partly in the fixed charge and partly in the volumetric charge. This tariff option has been defined so that the low use customers do not pay an increased fixed charge, and the lowest usage customers do not see a bill increase. The recovery of residual costs is split between the fixed charge and the volumetric charge, with about one third of the residual costs recovered in the volumetric charge.

Table 23

Introduce Three-Part Tariff, No Bill Change for Small Users

		Charges:	Fixed	Demand	Variable
Tariff components			150 to 400	75.00	0.03
Units			$/year	$/kW/year	$/kWh

Customers (% of total)	Annual consumption (kWh)	Peak demand (kW)	Total annual bill ($)	Components of the bill ($)		
10%	3,000	4	542.31	150.00	300.00	92.31
30%	6,500	4	900.00	400.00	300.00	200.00
10%	10,000	4	1,007.69	400.00	300.00	307.69
10%	3,000	8	842.31	150.00	600.00	92.31
30%	6,500	8	1,200.00	400.00	600.00	200.00
10%	10,000	8	1,307.69	400.00	600.00	307.69
Average revenue per customer ($/yr)			1,000.00			

Notes:
Demand charge set at LRMC; fixed charge for low kWh customers remains at $150/yr;
kWh charge set to recover some residual costs; no bill increase for low kWh/low kW customers.
Overall about 36% of residual costs are in the kWh charge, the balance in the fixed charge.

Table 24

Introduce Three-Part Tariff, No Bill Change for Small Users: Bill Impacts

Annual consumption (kWh)	Peak demand (kW)	Average tariff ($/kWh)	Bill change ($/yr)	Bill change (%)
3,000	4	0.18	0.00	0%
6,500	4	0.14	-100.00	-10%
10,000	4	0.10	-450.00	-31%
3,000	8	0.28	300.00	55%
6,500	8	0.18	200.00	20%
10,000	8	0.13	-150.00	-10%

C.   CONCLUSIONS ON TARIFF STRUCTURES

In this report, after describing the several principles that govern tariff design generally, we derived three principles that should govern the recovery of residual costs. Next, we reviewed examples of how residual costs are recovered from Great Britain, Italy and the United States. That led to the development of five stylized tariff options that could be applied in Australia. In this concluding section, we first evaluate the international examples against the three principles for recovery of residual costs. Then we evaluate the five specific Australian proposals against the same principles. To set the stage, we begin by recapping the issues that govern tariff design and residual cost recovery.

1.   Issues in recovering residual costs

In designing the structure of the DNSP tariffs, one important concern is efficient pricing. Efficient prices, to the extent that they are passed on through to the DNSP's customers by the retailers, help customers make optimal decisions in the long run about where to connect to the network, what size of connection to seek, and what kinds of appliances to install. And, in the short run, they help customers make optimal decisions about how often to run those appliances and at what times to run them. Setting DNSP tariffs at an efficient level is important because prices influence behaviour. Prices not set at the efficient level will induce inefficient outcomes (and if price did not influence behaviour, i.e., if price elasticities are zero or infinitesimally small, it would not be necessary to worry about setting efficient prices). For these reasons, the LRMC is an important consideration in setting DNSP tariffs.

In contrast, setting prices to recover residual costs as well as LRMC (i.e., the total authorized revenue requirement) implies that prices by definition will be inefficient if residual costs are significant. In particular, scaling all LRMC-based charges by the same amount sufficient to recover total costs means that the tariffs will be inefficient to the extent that price elasticities are non-zero and, to the extent that they differ across customers, tariffs could be made more efficient

by adjusting the recovery of residual costs. However, the ability to set multi-part tariffs—potentially including a fixed charge, a demand charge and a volumetric charge—offers a way to set prices that are closer to being efficient, because the three parts of the tariff differ in their impacts on customer behaviour. Recovering an additional $100/customer per year in a fixed charge will have no impact on customer behaviour.[67] Recovering an additional $100/customer per year in a demand charge or in a volumetric charge would have some impact on customer behaviour—as the price of electricity use increases, customers are likely to lower their usage.[68]

Despite the fact that multi-part tariffs potentially allow prices to be both reasonably efficient and the recovery of the authorized revenue requirement, our review of industry practice suggests that, for household customers at least, utilities typically do not set efficient DNSP tariffs. It is uncommon to have large fixed charges and instead residual costs are recovered in the volumetric charge. In the UK, for example, some DNSPs scale the LRMC-based volumetric charge by more than 100% to recover residual costs. Recovering residual costs in volumetric charges conflicts with pricing efficiency but has not stopped this approach from being practised widely. Other considerations—presumably equity and fairness—are held to be more important than efficient pricing. Perhaps there are concerns that raising fixed charges above a certain threshold will trigger a customer revolt.

Although not directly connected with the issue of residual cost recovery, it is worth noting that DNSP tariffs for households do not have LRMC-based demand charges, even though the network incurs most costs to supply demand (kW) and almost no costs to supply energy (kWh). In most jurisdictions there are no demand charges for household customers, and in Italy where there are demand charges, the demand charge is small. It recovers around 20% of the total revenue, whereas LRMC-based charges might typically recover 40%-95%.[69] Based on our review of industry practice and the relevant pricing literature, and our analysis of recent trends in the industry, there are two reasons which explain why utilities tend to recover residual costs in a kWh charge rather than in a fixed charge. The first reason is that recovering significant costs in a fixed charge is perceived to be unfair or inequitable. Customers who do not consume much electricity will have higher bills under such a system, and customers who consume a lot of electricity will have lower bills than under an alternative arrangement where residual costs are recovered in volumetric charges. We tentatively identify as a second reason that the price elasticity of demand has historically been quite small, so utilities lose relatively little revenue by increasing volumetric charges (and the resulting inefficiencies may be quite small). However, the introduction of rooftop solar technology means that price elasticity is changing: an increase in the volumetric charge that is sufficient to induce additional customers to install solar PV results in a large drop in those customers' consumption of kWh supplied by the DNSP. This change may

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[67] Assuming that charges are not large enough to induce customers to disconnect from the network entirely.

[68] There is a large body of literature on the price elasticity of energy consumption and a comparatively small literature on the price elasticity of kW demand.

[69] Based on the 14 DNSPs for Great Britain.

mean that the inefficiencies associated with recovering residual costs in kWh charges are greater now than they have been in the past, and it may also weaken the argument about the "fairness" of charging high, albeit cost based, fixed charges.

A related point, though not strictly concerning the recovery of residual costs, is that uptake of central air conditioning and rooftop PV in particular is causing significant divergences among customer load shapes. Consider four customers. The first one has central air conditioning, the second one has rooftop PV, the third customer has both central air conditioning and PV, and the fourth one has neither. The four customers will have different load shapes and load factors (ratio of average kW to peak kW) and will therefore impose different costs on the network. It is inequitable and inefficient to charge them the same volumetric tariff. The calculation of LRMC-based variable charges depends on an assumed load factor. This may be a reason to shift to demand charges rather than kWh charges for recovering LRMC (if smart meters are available) or a reason to divide customers into multiple classes with different tariffs if smart meters are not available.

2. International examples

We identified earlier three principles that are relevant to structuring tariffs to recover residual costs: economic efficiency, fairness and gradualism. However, these principles can conflict. It is therefore interesting to look at how residual costs are recovered in practice to see how trade-offs among the principles are made.

The principle of efficient pricing suggests that residual costs should be recovered in the fixed charge or perhaps in a declining block volumetric charge. In practice, this principle seems to influence tariff structure only weakly. In Great Britain the regulator and the utilities recently went through an extended process to redesign the methodology for determining distribution network charges, starting from LRMC-based prices. For household customers, 100% of the residual costs (which are significant for some of the DNSPs) are recovered in an uplift to the volumetric charge, and there is a single volumetric charge covering all households taking standard service. Thus, although the regulator and the utilities have recently taken a careful look at tariff design, efficiency considerations have not played a role in residual cost recovery for the household class. In Italy it is also clear that efficient pricing is not a consideration for the recovery of residual costs: the bulk of network costs are recovered through volumetric charges, and the volumetric charges are of the inclining block variety (the opposite of what one would expect if efficiency considerations were being applied). In many US jurisdictions efficient pricing does not seem to be a significant consideration for residual cost recovery. Transition costs (which are similar to residual costs in that they are costs approved for recovery over and above LRMC-based prices) were recovered in volumetric charges, or as a uniform uplift to existing tariffs in all the examples we are aware of. In Texas the distribution tariff has a flat volumetric component

and a relatively small fixed charge.[70] Massachusetts is unusual in that some decisions on tariff structure include an explicit discussion of the trade-off between principles. Efficient pricing plays some role in the structure of distribution tariffs, at least for gas networks. The volumetric charge for higher consumption is set on the basis of LRMC, and the residual costs are recovered partly in the fixed charge and partly in the first block of the declining block volumetric charge. The residual costs are not recovered entirely in fixed charges because to do so would conflict with the principles of fairness and gradualism.

We have not found much discussion of why efficient pricing is not a significant influence in these jurisdictions. One possibility is that regulators may not have identified significant inefficiencies associated with consumption or investment decisions by households. The price elasticity of demand is relatively low, and network charges are a relatively small component of total bills in many places. We noted above that these explanations may not hold when network costs are rising and when customers have the option to install solar panels.

The principle of fairness seems to be a driving consideration in some cases, even if it is not clear exactly how the principle is being used to determine tariff structure. In Italy the distribution tariff is explicitly designed to provide a discount to smaller customers. Both the fixed charge and the demand charge are lower for customers with peak demand of 3kW or less. Furthermore, there is a steeply inclining block structure to the variable charge. The inclining block structure of the variable charge allows additional revenues to be collected that support the below-cost tariff for smaller customers.

In US jurisdictions the fairness principle is often cited in proceedings to determine the structure of tariffs. There is specific judicial language that calls for rates to be "fair, just and reasonable." While that language originated in Supreme Court cases involving the revenue requirement, it has been invoked in cases involving tariff design. As noted earlier, it is often difficult to translate the concept of fairness in rate design, since there are multiple interpretations of fairness. It is often argued, for example, that high fixed charges are unfair to small users. At the same time, of course, distribution costs are largely fixed and thus it is economically efficient to recover them through fixed charges. The principle of gradualism, which effectively puts significant weight on maintaining existing tariff structures, is also frequently cited in US jurisdictions and seems to exert considerable influence on rate making practice. In Massachusetts, fairness and gradualism result in a tariff structure that recovers some of the residual costs in the fixed charge and recovers the rest in the first block of a declining block volumetric charge.

3.   The five stylized tariff structures

We discussed above five stylized tariff structures that might be applicable to the Australian market:

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[70]   We note, however, that the total distribution tariff in Texas is relatively small, and residual costs are not explicitly identified and may be small.

1. Postage stamp pricing which raises the volumetric charge proportionately across all customers to recover the residual cost.

2. Ramsey pricing applied to the volumetric charge which translates into a declining block tariff.

3. Gradually transitioning to recovering the residual cost through the fixed charge and setting the volumetric charge equal to LRMC.

4. Exempting vulnerable customers from an increase in the fixed charge.

5. Introducing LRMC-based demand charges and sharing residual cost recovery between the fixed charge and the variable charge.

Postage stamp pricing raises prices above LRMC proportionately for all customers. To that extent, it would appear to be consistent with the principle of fairness. However, raising prices above LRMC results in inefficient prices if the price elastic of demand is non-zero. In particular, the option of raising the fixed charge, which by definition induces no changes in behaviour, would result in more efficient prices than the postage stamp option. To the extent that price elasticities differ across customers, different customers may make different proportional adjustments in how much electricity they consume as the variable charge is increased to recover residual costs. Thus, the amounts consumed by different customers in response to the price change may deviate from their optimal quantities (what they would have consumed if LRMC pricing was followed) by unequal amounts. This would create further inefficiencies. Because current tariffs do not recover large amounts of residual cost in the fixed charge, postage stamp pricing could conform to the principle of gradualism. For DNSPs which currently use a block structure for the volumetric charge, the change could be large for some customers. If the change is large, it could be phased in over time, allowing the principle of gradualism to be achieved.

Ramsey pricing ensures that deviations from optimal quantities are proportional across customers and thus would conform to the principle of economic efficiency. However, for that very reason, it would confirm to the principle of fairness. As for gradualism, if the price changes are small, that principle would be adhered to. If the changes are large, an option for policy makers would be to phase in the changes over a five to seven year period.

Gradually raising the fixed charge and setting prices ultimately equal to LRMC would conform to the principle of efficiency. It may be regarded as unfair by those who want to protect small users from having to pay a large fixed charge, but, at the same time, it involves all customers paying the same share of residual costs. Whether this option is regarded as "fair" depends on the interpretation of the fairness principle, which, unfortunately, has several conflicting interpretations. Since the option involves gradually changing prices, it would conform to the principle of gradualism.

Exempting vulnerable customers from price hikes would not conform to the principle of economic efficiency. It may be perceived as fair by the vulnerable customers and unfair by all

other customers who will then have to shoulder the entire recovery of residual costs. It would conform to the principle of gradualism for the vulnerable customers since they will not see any change in prices. It would not conform to that principle for all other customers unless the increase in prices is phased in. However, a further difficulty with using tariff design to protect vulnerable customers is that the tariff itself may be a rather blunt tool. For example, tariffs designed like those in Italy to provide a discount to customers with low consumption may provide discounts to many customers who are not vulnerable, and miss many who are.

Introducing demand charges set at LRMC would be consistent with the principle of economic efficiency. This would be more efficient than LRMC-based volumetric charges (since demand rather than kWh drives network costs). It would also be fairer since customers with higher demands would pay higher amounts than customers with lower demands. Of course, if it is done instantly, it would not conform with the principle of gradualism.

We also considered two other options for recovering residual costs. The first of these would recover the residual costs from other customer classes, such as commercial and industrial customers. This approach might side-step fairness considerations (if fairness is interpreted to apply only to personal rather than business customers), and could be consistent with efficient pricing if the residual costs could be recovered through fixed charges in a way that did not distort demand. The second of these options would divide the residential class into sub-classes according to load factor, and develop LRMC estimates that are specific to each sub-class. Thus, customers with central air conditioning would have a different LRMC than customers without central air conditioning, customers with rooftop solar panels would have a different LRMC than those without rooftop solar panels and so on. Separate prices would be developed for each of these sub-classes and residual revenue recovered accordingly. In some ways, this method would approximate our fifth method which involves demand charges.

4.   Conclusions

We have not identified any single "best" approach for the recovery of residual costs. If the principle of efficient prices is prioritized, the recovery of residual costs through fixed charges would result. In practice this approach is not followed because it conflicts with the principles of fairness and gradualism. The gradualism principle recognizes the fact that customers may have made investment decisions expecting current tariff structures to continue into the future. Unlike efficiency or gradualism, however, the principle of fairness is not clearly defined. In practice, regulators have to strike a careful balance between these three principles, making trade-offs to reflect relevant policy considerations. Transparency in how this balance has been struck, and in how the principle of fairness is being interpreted, would be helpful in clarifying the respective roles of tariff design and other policy instruments in achieving desirable outcomes.

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