On the Inequity of Flat-rate Electricity Tariffs

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ABSTRACT

Proposals to reform default 'flat-rate' electricity tariffs are rarely met with enthusiasm by consumer groups or policymakers because they produce winners and losers. Proposals to initiate more cost-reflective time-of-use rates will be met with cautious interest if the basis of customer participation is 'opt-in'. Using the smart meter data of 160,000 residential customers from the Victorian region of Australia's National Electricity Market, our tariff model reveals that households in financial hardship are the most adversely affected from existing flat-rate structures. Even after network tariff rebalancing, Hardship and Concession & Pensioner Households are, on average, beneficiaries of more cost-reflective tariff structures once Demand Response is accounted for.

Keywords: Dynamic Pricing, Electricity Tariffs, Smart Meters

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INTRODUCTION

In Australia, residential electricity prices are structured as conventional two-part tariffs comprising a fixed charge and a 'flat-rate' variable energy charge. The origin of the two-part tariff can be traced back to the electricity supply industry in 1892. The design by Hopkinson (1892) reflected the atypical cost characteristics of power systems—a non-storable commodity with a cost structure overwhelmingly driven by periodic demand rather than annual energy demand. Expected peak loads during extreme weather 'critical event' days drive system capacity, and capital-intensive capacity costs (as opposed to system marginal running costs) dominate the cost structure of electricity supply. The fixed and sunk capital costs of an electricity distribution system will typically comprise 70–80% of the total network cost structure. The Australian east coast generation fleet has a similar cost structure. The two-part tariff was theoretically designed to capture these characteristics and originally comprised a demand charge (expressed in dollars per kilowatt or $/kW) reflecting peak capacity utilised by a customer, and a variable energy charge (expressed in cents per kilowatt hour or c/kWh) reflecting the real-time marginal running costs of the power system. There was a difficulty with implementing the *theoretically optimal* two-part tariff, however. Power system peak load typically occurs on 12–15 critical event days each year and in order to levy a demand charge, measurement of coincident customer peak load is necessary. For most of the past 120 years, meter technology has been a limiting factor—for households it was simply uneconomic to install two meters and so a surrogate demand charge would be required (i.e. a fixed charge). To be clear, most households in Australia still have a mechanical meter which requires a meter reader to physically inspect and record metered electricity use.

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In Australia, the fixed charge is levied on a uniform basis and therefore involves an arbitrary, and by implication inequitable, allocation of fixed costs. A uniform fixed charge bears some relationship with direct connection costs, but no relationship with household peak loads during critical events. Moreover, in Australia the fixed charge has become a surprisingly small component of the two-part tariff. Given the nature and cost of the network, this aggravates the inequity of existing tariff structures relative to the cost of supply.

The purpose of this article is to analyse efficiency gains and inter- and intra-segment wealth transfers arising from existing flat-rate tariffs in the context of a power system experiencing suboptimal load growth.[1] We do this by contrasting the existing flat rate with the more cost-reflective *Time-of-Use* and *Critical Peak Prices*. We should emphasize that we do not attempt to redress the optimal level or structure of the fixed charge. Nor do we contemplate other tariff designs such as one dominated by a demand charge—an alternate solution which is at least as valid.[2] Instead, in this article we focus on analysing inequities that exist by assessing the changes arising from a more cost-reflective time-differentiated structure and build on the applied analysis contained in Simshauser and Downer (2012).

Our analysis makes use of AGL Energy's *SAP HANA*, an ultra-high speed in-memory computing appliance which enables us to work rapidly with a truly vast data set. Our modelling incorporates 2.8 billion meter reads from 160,000 smart meter customers from Victoria (i.e. 17,520 meter reads for each customer, representing a full year of half-hourly consumption data). Approximately 6000 of these households were matched with AGL Energy's online household survey (one of Australia's largest ongoing household surveys with more than 70,000 entries[3]). This combination of data sources enables us to analyse inter- and intra-segment wealth transfers. By specifying a set of broadly representative household cohorts, our analysis of tariff reform should be of interest to the electricity industry, consumer groups and policymakers.

We have structured our article as follows. In Section I, we review the relevant literature while in Section II we provide an overview of default electricity tariffs. In Section III, we present average daily load shapes for five different household cohorts. Section IV outlines our tariff model and pricing structures while Section V reviews model results. Our policy implications and concluding remarks follow.

I. REVIEW OF LITERATURE

The two-part tariff was developed by electrical engineers in the 1890s—initially by Hopkinson (1892). The two-part tariff represented the means by which to charge electricity consumers in a fair, efficient and equitable basis—reflecting meticulous engineering cost analyses undertaken by these early power system engineers. From an applied perspective Wright (1896) from the United Kingdom and Greene (1896) from the United States demonstrated in considerable detail that the primary cost driver of their respective 'central' power systems was *not* variable production costs, but rather, the cost of installing and maintaining the capacity required to meet aggregate peak load.[4]

1. By suboptimal load growth, we mean a power system with a deteriorating load factor.

2. See for example Simshauser (2014c).

3. Note however this survey focuses on the composition of the household (number of inhabitants, rooms, housing material, appliance stock etc) and does not seek to collect data relating to household income.

4. Variable power station fuel costs and network line losses are known to pale into insignificance by comparison to the investment commitment associated with building power station equipment and a network of poles and wires to meet peak summer loads.

Based on these principles, early tariff engineers concluded electricity prices should take the form of a 'two-part tariff' comprising a demand charge according to customer peak load ($/kW), and a variable energy charge based on the volume consumed (c/kWh).[5] In a practical sense the limiting factor at the time (and for the ensuing century or more) was the cost and availability of interval metering. Given this data constraint, at the residential level the substitute for the demand charge would be the *'fixed charge'*. Early applications of the residential fixed charge for electricity supply were driven by demographic indices. In England for example, the fixed charge was linked to the number of bedrooms or the rateable value of the property in question (Lewis, 1941). The fixed charge would be adopted by the electricity industry around the world and in time the two-part tariff would be extended to other industries such as gas supply, water supply, telecommunications, rail transport, the taxi industry and so on.

Contemporary applications of the two-part tariff in the Australian electricity supply industry are dominated by the variable charge. That is, over time, the uniform fixed charge element of the two-part tariff has decayed considerably.[6] As our data later reveals, the fixed charge currently comprises 10% of the overall tariff structure for an average customer. For a power system experiencing rapid underlying energy growth (e.g. due to rising appliance use such as air-conditioners), a two-part tariff structure dominated by a 'flat rate' variable charge could be argued as desirable against a range of tariff design criteria.[7] But in a system experiencing sharply rising peak load growth, declining underlying energy demand, or both, a two-part tariff with the structure dominated by a flat rate variable charge does present certain difficulties. Above all, it can become unstable and risks inducing an inefficient allocation of resources, thereby violating other elements of conventional tariff design criteria (see for example Boiteux & Stasi, 1952; Bonbright, 1961). This was the primary theoretical motivation of Hopkinson (1892) and the applied findings in both Wright (1896) and Greene (1896) because at the time, these power systems were experiencing sharp and unsustainable growth in system peak load.

A key issue for the electricity industry and for policymakers is that with flat rate tariffs and periodic demand, the value of peak energy is under-priced while the value of off-peak energy is overpriced.[8] The absence of widespread time-differentiated pricing has been persistently identified as a problem facing the efficiency of electricity systems by energy economists dating at least as far back as Boituex (1949), Dessus (1949), Houthakker (1951), Steiner (1957), Nelson (1964), Turvey (1964), Joskow (1976), Crew & Kleindorfer (1976), and Wenders (1976).

More than a century has passed since the ideal theoretical tariff structure was specified (see Hopkinson, 1892; Greene; 1896; Wright, 1896), and more than half a century has passed since energy economists generalised and optimised the principles for mass market application (see Lewis,

5. A third charge reflecting the cost of connection was also suggested.

6. The substantial rise in household consumption over long timeframes (e.g. 1955–2008) and the political economy of increasing fixed charges above inflation rates has driven this 'decay'. As Simshauser, Nelson and Doan (2011) explain, household consumption in the Queensland and New South Wales regions averaged 2,000kWh per annum in 1955. This doubled to 4000kWh by the 1970s and doubled again to 7900kWh by 2008. Consequently, variable volumes (and revenues) have increased by a factor of *3–4x* since 1955.

7. In a power system experiencing strong underlying energy demand growth, a two-part tariff with a high variable (low fixed) component can meet the objectives of simplicity, stability and revenue adequacy because, given constant or increasing returns to scale, the structure may over-recover revenues if tariffs are pegged to inflation rates. That is, the combined effects of underlying demand growth and price inflation can over-recover revenues given the dominance of non-inflationary sunk costs within the cost structure.

8. Simshauser & Downer (2012) provide a static analysis to demonstrate this concept as so we propose not to reproduce this here.

1941; Boiteux, 1949; Houthakker, 1951; Boiteux & Stasi, 1952). Only recently, however, have smart meters become economically viable at the household level. In the case of Victoria, at the time of writing a mandated network monopoly roll-out of smart meters was in its final stages. The deregulation of metering services has also become a key thematic in other regions of Australia.[9] These developments raise the prospect of meaningful electricity tariff reform, and the potential to substantially reduce inter- and intra-segment cross subsidies.

Faruqui & Malko (1983), Borenstein & Holland (2005), Faruqui (2010a, 2010b), Faruqui & Sergici (2010, 2013), Faruqui, Sergici & Sharif (2010), Wood & Faruqui (2010), Faruqui & Palmer (2011), Simshauser & Downer (2012), Borenstein (2013), Procter (2013), Nelson & Orton (2013), Energex & Ergon (2014), Horowitz & Lave (2014), Fenwick et al. (2014) and others have all demonstrated that with the availability of smart meters, time-of-use tariff structures are capable of correcting market inefficiencies and inequities.[10] Furthermore, the literature on price discrimination[11], which is well summarised by Armstrong (2006, 2008), notes that as firms in competitive markets access more ornate tariff structures, it has the effect of amplifying competition because they equip themselves with a new arsenal of weapons to attack competitors to gain market share, which in the end enhances consumer welfare. The combination of smart meters, time-differentiated structures and non-linear pricing more generally will invariably drive product innovations not possible in their absence.

Our experience, however, is that consumer groups approach the notion of default tariff reform with a concern that their constituents will be adversely affected by greater cost-reflective prices (see for example Alexander, 2010; Brand, 2010; CUAC, 2010). With the notable exception of St Vincent de Paul, most consumer groups in Australia argue that existing tariff structures should be made 'even more simple'—the logical extreme presumably being an average cost variable tariff (i.e. uniform flat price, no fixed/demand charge element). However, as our quantitative analysis subsequently reveals, such thinking is not supported by the evidence presented in this article.[12]

9. A generalised framework for the roll-out of smart meters has been agreed by policymakers in Australia. Specifically, in 2007 the Council of Australian Governments agreed to develop a National Smart Meter Framework based on a mandated rollout by distribution networks (i.e. where benefits outweighed costs). The Victorian mandated smart meter roll-out was not done well and since then, more recent reviews including those by the Australian Energy Market Commission have tended to favour a retailer-led competitive metering framework for future smart meter roll-outs (as is the case in New Zealand and Great Britain). See Nelson and Simshauser (2014).

10. Borenstein & Holland (2005) and Horowitz & Lave (2014) examine Real-Time Pricing.

11. To be clear, while the literature on price discrimination finds its roots in monopoly applications, a special strand emerged which analyses the role of differential prices in competitive industries. One of the original contributions on competitive markets came from Salop and Stiglitz (1977) which focused on informed (weak segment) and uninformed (strong segment) customers and was later extended by Katz (1984) although the use of completely inelastic demand functions limits welfare enhancements. The literature on non-linear pricing in symmetric markets (where firms agree on strong and weak customer segments) finds that uniform pricing will typically be lower than a default price but higher than marginal prices (Borenstein, 1985; Holmes 1989; Winter, 1997; Dobson and Waterson, 2006). In the event, the net effect on consumers is ambiguous. But Corts (1998) shows that in markets where firms do not agree on which customer segments are 'strong' and 'weak', the presence of price discrimination is likely to reduce overall prices and enhance consumer welfare. Bester and Petrakis (1996) find banning discrimination raises marginal prices and as with Shaffer and Zhang (2000), conclude that this always damages some consumer groups. Shaffer and Zhang (2000) also derive conditions by which all consumers can be damaged. Hviid and Waddam Price (2012) examined limits placed on non-linear pricing by an electricity regulator in the British energy market and found the response by firms to non-discrimination rules generated detrimental distributional effects and had a range of unintended adverse consequences. Specifically, they found that because the market was asymmetric with regards to which customers were strong and weak, the result was to raise all prices as the literature predicts. The regulator found in a post-implementation review that many indicators of competition had deteriorated and in the event, abandoned the policy.

12. Wood and Faruqui (2010) also provide counter evidence in relation to low income households.

Consumer group support is likely to be 'cautiously optimistic' if tariff reform is based on an 'opt-in' approach. Borenstein (2013) explains how such an approach might be best implemented in order to accelerate an otherwise long transition process (i.e. creating a virtuous cycle comprising two customer pools, shadow billing, monthly invoicing and bill smoothing mechanisms).

An average cost variable tariff is not efficient and is likely to produce inequitable outcomes, and when combined with sharply rising peak demand growth, contracting energy demand, or both, an average cost tariff structure may become unstable. The reason for this is that under either of these scenarios, the relevant fixed and sunk network costs are spread across fewer units of output. Under rate-of-return regulation, tariffs must be continuously increased to offset volumetric losses. To make matters worse, such rate structures will amplify implicit or 'hidden' Solar Photovoltaic (Solar PV) subsidies and can drive investment in PV systems above otherwise efficient levels.[13] Under these conditions it is not difficult to see how an average cost variable tariff has a particularly high propensity to induce an *energy market death spiral*[14] (see for example Severance, 2011; Simshauser & Nelson, 2014).

II. REVIEW OF EXISTING DEFAULT TARIFF STRUCTURES

Our quantitative work starts by reviewing historic tariff levels and the structure of existing default tariffs. The former is of course the sole reason why electricity tariff reform warrants discussion at all. In this Section we present data from the Queensland region of Australia's National Electricity Market, where we have a particularly long time series.

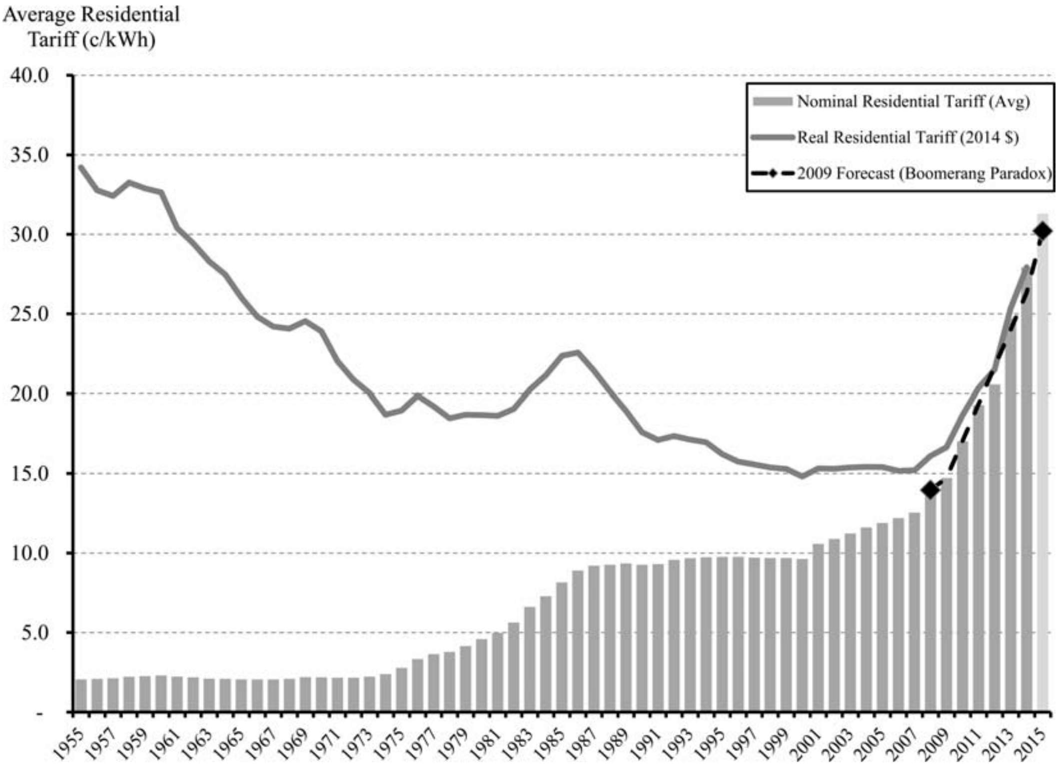
Figure 1 presents residential electricity tariffs from 1955–2015*f* in nominal (bar series) and real (line series) terms. Note also the '2009 Forecast' markers (and dashed line series) which runs from 2008–2015. This price forecast, initially produced in 2009 and subsequently published in Simshauser, Nelson and Doan (2011), indicated that electricity tariffs would increase from 14.5/kWh to 29c/kWh between 2008–2015. As Simshauser and Nelson (2014) explain, tariffs would double in the space of just seven years in an ostensibly low inflation environment—and to put this into perspective, it took 23 years (from 1985 to 2008) for electricity tariffs to double previously—much of this in a high inflationary environment. The rapid doubling of residential electricity tariffs to 2015 seemed entirely predictable due to rising equipment costs, rising renewable energy subsidies, the introduction of carbon taxes, and above all, a tightening of reliability standards leading to rapid increases in transmission and distribution network investment to meet forecast peak demand growth.[15]

13. Solar PV output peaks around the middle of the day whereas the peak load of many distribution network elements occurs between 4–9pm. Households with a Solar PV unit are 'net metered', meaning that variable network charges are avoided without any material reduction in the use of the distribution system during the 4–9pm peak period. This has resulted in considerable hidden cross-subsidies to Solar PV households, and financed by non-Solar PV households through the network tariff rebalancing process. See Simshauser (2014c).

14. Simshauser and Nelson (2014) describe an *energy market death spiral* as a situation whereby contracting demand results in an increase in the price of electricity (i.e. to meet regulated revenues). This tariff increase induces a demand response, and in turn, a further round of price increases. Wealthier households respond by introducing Solar PV units, further reducing demand and driving yet another round of tariff increases, and so on. Our point here is that a death spiral is more likely when the variable charge dominates the structure of a two-part tariff.

15. Simshauser and Nelson (2013) explain that the most recent surge in electricity tariffs should moderate through to 2020 due to the removal of the carbon tax, changes to renewable energy policies and subsidies, and the completion of the major capital expenditure cycle associated with networks.

Figure 1: Queensland Residential Tariffs: 1955–2015*f*



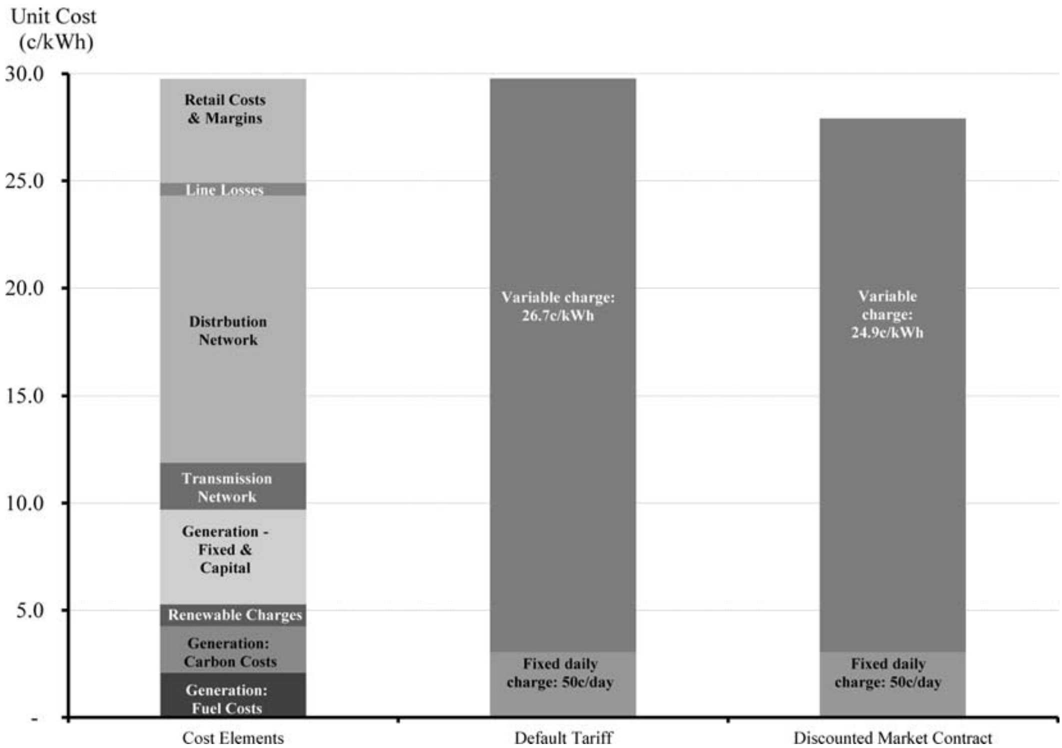
Source: Simshauser, Nelson and Doan (2011).

The single largest contributor to the 2008–2015 increases would come from the regulated monopoly charges for electricity networks, with pricing set under five-year rate determinations by the Australian Energy Regulator. The five-year regulatory period spanned either side of the Global Financial Crisis and submissions by monopoly network businesses, and accepted by regulatory authorities, assumed strong growth in peak demand. This set the scene for record levels of capital investment in network infrastructure[16] which in the event increased from $10 billion to almost $40 billion over the five-year period to 2014 (Simshauser, Nelson and Doan, 2011). Tariffs were set to rise sharply. However, a problem emerged. The financial crisis of 2008–2009 took its toll on energy demand and by 2010 Australia experienced its first year of electricity demand contraction on record. Then, overlapping State and Federal Solar PV subsidies (and hidden subsidies arising from the existing two-part tariff structure) induced an over-investment in solar PV units which accelerated contractions in system electrical demand. Combined, this further aggravated tariff increases and led to further demand contractions.[17] With network investment plans committed and regulated revenues assured, the price surge was predictable.

16. Abnormally stringent reliability standards introduced during the mid-2000s contributed to overinvestment in Queensland. See Simshauser (2014b) for details.

17. The contraction of energy demand is thought to be the product of three primary drivers at the household level; (a) the own price elasticity of electricity, (b) the rising efficiency of new appliances, and (c) the sharp run-up in subsidised rooftop solar PV units.

Figure 2: The Cost Elements and Structure of Residential Electricity Tariffs (Queensland 2014)



Source: Simshauser (2014a).

How tariffs are structured is presented in Figure 2. The first bar presents the actual cost elements of electricity supply, while the second bar presents the existing default tariff structure and the third bar is reflective of a typical discounted competitive market product using Queensland 2014 data. The default tariff comprises a fixed charge of $0.50 per day with a variable energy charge of 26.7c/kWh. For the typical Queensland household consuming 6,000 kWh per annum, 10% of the total electricity bill of *ca.*$1750 per annum is levied by the fixed charge, whereas capacity-related industry fixed costs comprise 64% of the total.[18] Additionally, as noted earlier the fixed charge is applied at a uniform rate—regardless of household characteristics.

III. HOUSEHOLD LOAD SHAPES

Until only a few years ago, all 8 million households in Australia's National Electricity Market had a mechanical meter which was physically read four times per annum. Convention was for the household to receive a quarterly electricity bill which would tell the account holder how much electricity (in volumetric terms) had been consumed every 90 days and would reflect seasonality—but little more. However, the rising penetration of smart meters means that we now have

18. Industry variable cost includes: generation fuel, carbon costs, 20% of network costs, line losses and 52% of retail costs.

a better understanding of household load shapes. In this article, we present five variations to our Overall Average household load shape based on demographic characteristics (albeit *excluding* household income) from Victoria.

1. Working Couples, No Kids (n = 2000);
2. Working Parents with Kids (n = 2000);
3. Family, Parent at Home (n = 2000);
4. Households in Hardship (n = 1800);
5. Concession & Pensioner Households (n = 60,000); and
6. Overall Average (n = 160,000).[19]

Note that n = 2000 for cohorts 1–3, n = 1800 for cohort 4 and n = 60,000 for cohort 5. To be clear, in the context of the Overall Average cohorts 4 and 5 are broadly representative of the customer base. Clearly, our sample size for demographic cohorts 1–3 are not—they are reflective of available data from AGL Energy Ltd's on-line household survey, and, there are many other valid cohorts that we have missed (e.g. single parent household etc). As such, these cohorts should not be considered exhaustive. Additionally, this is merely one of many methods by which to analyse household cohorts. Other variables that could be used to segment the data include age of account holder, owners vs. renters, household income, product selected, and so on. However, with these qualifications, and for the purposes of our inquiry and analysis into the efficiency and equity of existing tariff structures, this particular stratification of the data will, in our opinion, serve as useful and provide guidance to policymakers.

A. Working Couple, No Kids

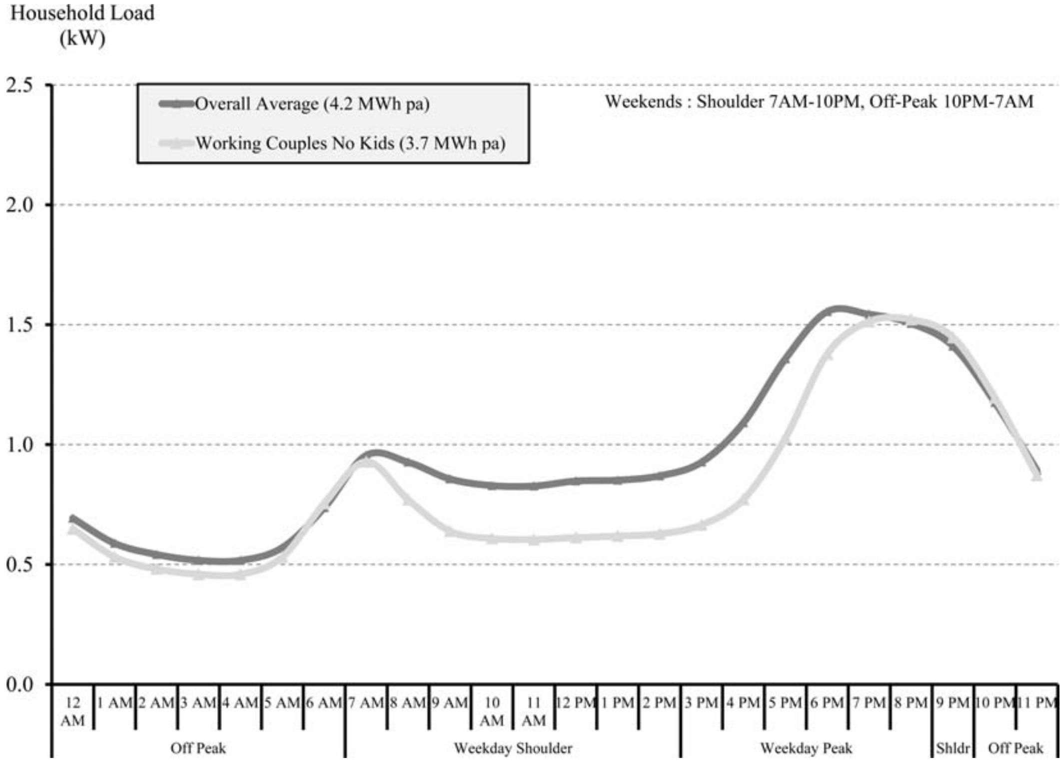
Figure 3 illustrates the annual weekday average electricity consumption from two distinct household types. The x-axis measures the time of the day from 12 midnight through to 12 midnight, and the y-axis measures the household electricity load in approximate[20] kW. Our benchmark household load curve, referred to as the 'Overall Average' and represented by the dark grey line series, is based on 48 half-hour final demand data points for each workday and reflects the average of the 160,000 households from Victoria and their 2.803 billion meter reads throughout the year. It should be noted that this load curve does not represent peak summer or winter days. It is the annual weekday average, but is nonetheless a helpful graphical representation of our data for cohort comparison purposes. Figure 3 highlights that the Overall Average household uses 4.2 MWh per annum and that the peak load occurs at 7pm. It is worth noting that our data explicitly excludes hot water loads (i.e. most Victorian households have gas hot water, and those that do have an electric hot water system are a controlled load on a cost reflective tariff).

The light grey line plots our first cohort—Working Couples, No Kids. This cohort is dominated by young professionals living in central city locations with proportionately more account holders below 40 years of age, and a high proportion occupying rental properties (*ca.*40% vs.

19. At the time of writing, AGL Energy Ltd had approximately 3.8 million customer accounts. This included 665,000 electricity customers in Victoria, and of these, 160,000 had a smart meter installed at least 12 months prior. Our analysis focuses on these 160,000 customers since we were able to analyse a full year of consumption data (i.e. 17520 half-hour intervals per household).

20. Our smart meter data is the accumulation of 30 minute consumption. Real-time data would oscillate around the mean result.

Figure 3: Annual Average Weekday Load Curve: Working Couples No Kids



Source: AGL HANA.

Overall Average of *ca.*25%). These households use only 3.7 MWh excluding hot water. Notice that during the day, they use very little electricity (i.e. nobody is home) and arrive home later than the Overall Average (i.e. their evening ramp-up is delayed by an hour).

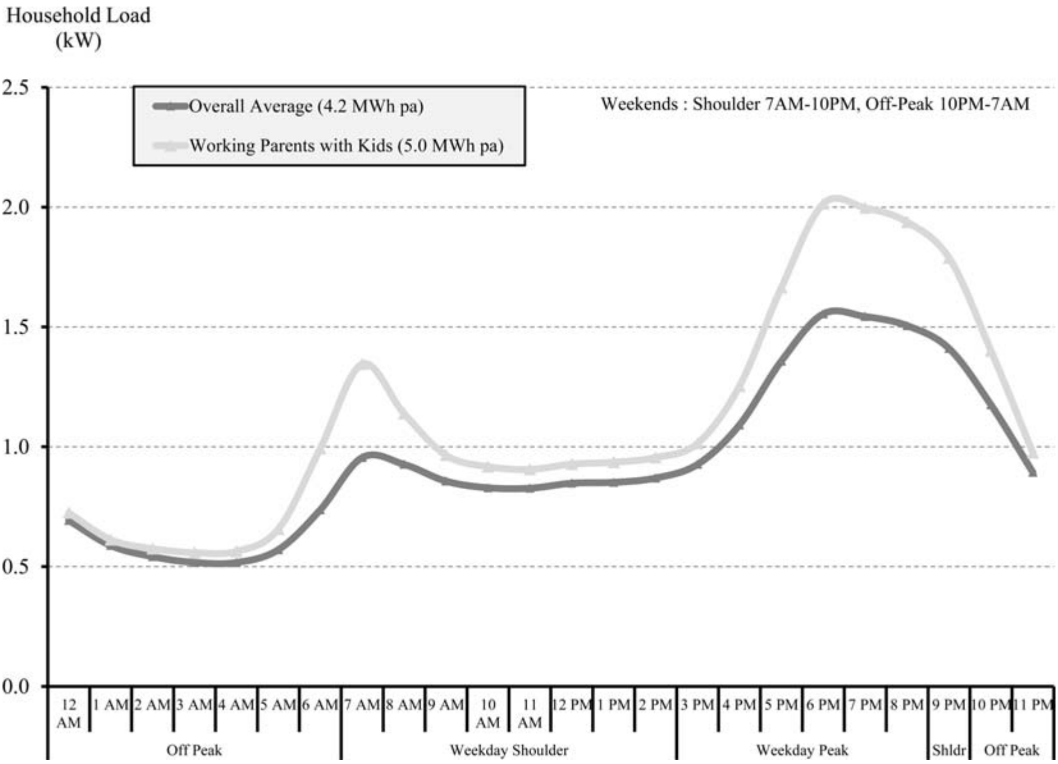
B. Working Parents with Kids

In Figure 4 we present our household load for Working Parents with Kids. As Simshauser and Nelson (2014, p.30) explain, these households have:

> *. . . two or more uncontrollable consumers (that is, children) who are blissfully unaware and unmoved by the financial impact of the uncoordinated, and in many cases, simultaneous energy consumption decisions arising from the use of computers, game controls, televisions and heating and cooling devices . . .*

Households with children have noticeably larger morning and evening peaks. These account holders are dominated by 36–64 year olds in major and high growth metropolitan suburbs. With both parents working, the household organises itself earlier, and so the morning load commences its run-up earlier than average. Notice also that the addition of children to a household means that the afternoon ramp-up in load commences from about 3:30pm when children arrive

Figure 4: Annual Average Weekday Load Curve: Working Parents with Kids



Source: AGL HANA.

home from school, whereas for Working Couples, no Kids, this occurs from 5pm or later when adults arrive home from work.

C. Family, Parent at Home

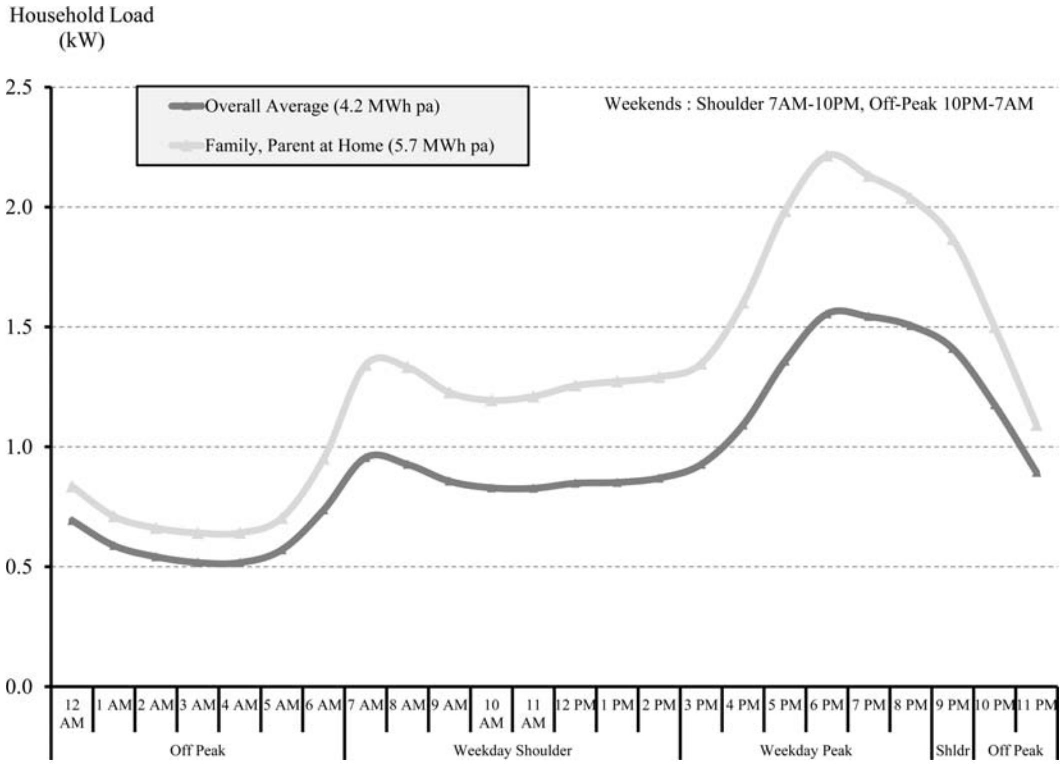
In our next customer cohort, we examine a family comprising parents and children but unlike Figures 3 and 4, in this instance one adult is at home during the day. This results in a profoundly different load shape as Figure 5 demonstrates. In relative terms, these are large household customers at 5,700 kWh per annum ex-hot water load. They use more power during each half-hour interval with a noticeably strong consumption pattern during shoulder and peak periods.

D. Household in Hardship

Our next cohort is of special interest to our analysis, and should be to policymakers, because they represent the group of customers who can least tolerate inequities or inefficiencies in tariff design—Households in Hardship.[21]

21. For our purposes, 'Households in Hardship' are defined as those households who have the willingness, but not the financial capacity, to pay their electricity account. They have in turn been placed on AGL Energy's 'Staying Connected' program.

Figure 5: Annual Average Weekday Load Curve: Family, Parent at Home



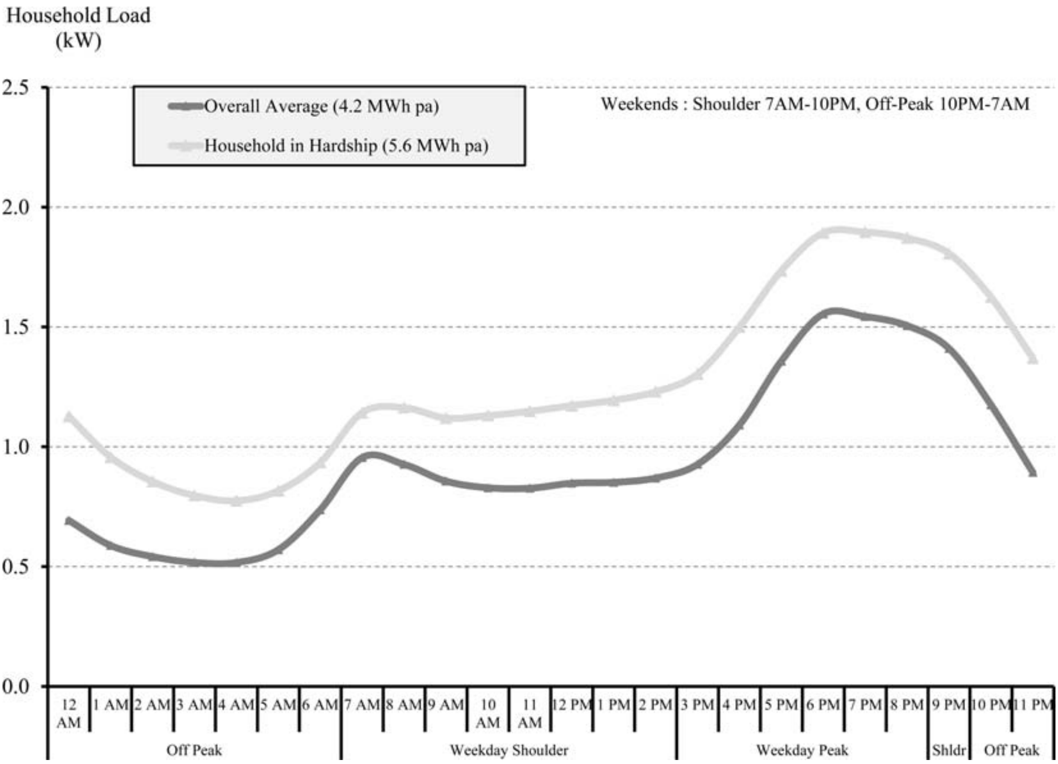
Source: AGL HANA.

This data took us by surprise. Following on from Simshauser and Nelson (2014), we had anticipated that Households in Hardship would be large users (i.e. large electricity bills), but we had not anticipated the extent of off-peak consumption. This may reflect variables such as the quality of materials used in the housing stock (e.g. limited insulation), a less efficient electrical appliance stock, and some element of anthropogenic pattern driven by the circumstances facing these households. As Simshauser and Nelson (2014) indicated previously, the age of account holders in this cohort are dominated by 36–55 year olds with a median age of 44 years. Above all, because this cohort exhibits the most favourable load factor, they will be the most adversely affected from continued use of existing tariff structures. To be perfectly clear on this, consumer advocates seeking to retain simple flat tariffs or *further simplify* tariff structures by moving to a single variable rate are almost certainly (albeit inadvertently) doing more damage than good to this cohort—something we demonstrate quantitatively in Section V.

E. Concession & Pensioner Households

Our final cohort is Concession & Pensioner Households which is dominated by account holders greater than 65 years of age and a very high 'home ownership' level of 86%. They are low energy users with annual volumes of 3,600 kWh.

Figure 6: Annual Average Weekday Load Curve: Household in Hardship



Source: AGL HANA.

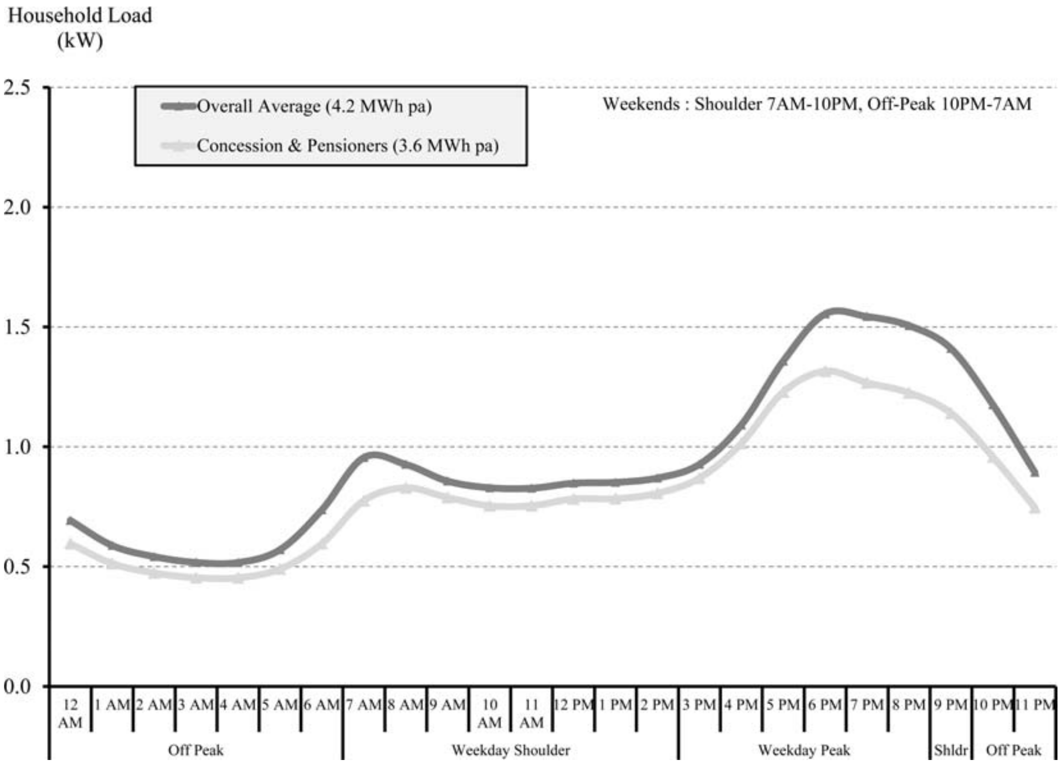
F. Price Elasticity & Demand Response

A crucial component of the following analysis is our elasticity estimates. Our tariff model alters the rate structure from a uniform variable charge to time-differentiated variable charges, specifically, peak, shoulder and off-peak rates along with a 'Critical Peak Price' dynamically applied to 12 critical event days. In Figure 8, we present Faruqui and Sergici's (2013) Demand Response summary from 163 tariff pilots from US, Australia and France amongst others.[22] Each of the bars presents the average reduction in household peak demand (in percentage terms) from a change in tariff design.

There are six distinct sets of results in Figure 8 which rank the response by consumers to changes in rate structures. The first set of results (i.e. trials 1–42) present the average Demand Response by consumers during peak periods when customers are shifted from a uniform variable charge to time-of-use (TOU) charges. Note that Demand Response in these pilots, denoted TOU in Figure 8, resulted in an average peak reduction of 7.4%. When enabling Demand Response technology (TOU + Tech) was included (i.e. trials 43–65) the average peak reduction was 16.9%. The next set of pricing pilots involved a Peak-Time Rebate (PTR) product in which households are paid

22. Note that these pilots were all 'opt-in' and are therefore exposed to selection bias.

Figure 7: Annual Average Weekday Load Curve: Concession & Pensioner Households



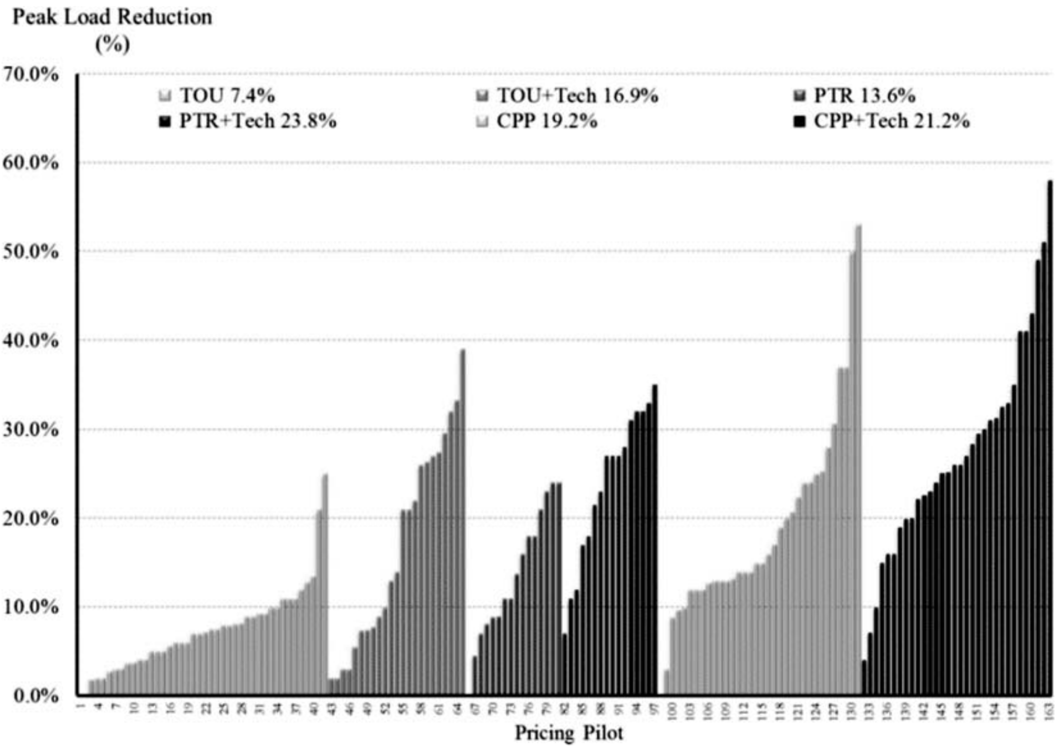
Source: AGL HANA.

if their peak load is reduced and average a 13.6% reduction. When enabling technology is added the average reduction increases to 23.8%. The final trials involve Critical Peak Prices (CPP) and result in peak load reductions of 19.2% on average (which increases to 21.2% with enabling technology).

Energex & Ergon (2014) find similar results for Queensland-based residential customers in their CPP pilot, with average peak load reduction on critical event days also being 19% (and 24% load reductions for low income households). So how do Australian households physically respond to Critical Peak Prices on event days? In their pricing pilot in Queensland, Energex & Ergon (2014) surveyed how households responded during critical events—8% found it difficult to respond, whereas 71% found it easy. A summary of their actions is provided in Figure 9.

From our perspective, an unexpected result in Energex & Ergon (2014) was low-use households were more capable of shifting peak loads than medium- and high-use households. In our previous research in this area (see Simshauser and Downer, 2012), we had explicitly assumed that households consuming less than 2500 kWh pa were largely price inelastic based on the findings in Reiss and White (2008). While this is no doubt valid with respect to total consumption, it is evidently not valid with respect load shifting. That is, low-use households such as Concession & Pensioners will probably not reduce their overall annual consumption levels, but *they can and do respond* to time-differentiated prices during critical events by shifting load as Figure 9 reveals (see also Wood & Faruqui, 2010). Accordingly, in our present analysis we estimate own price elasticity to be −0.05

Figure 8: Peak Load Reductions from 163 Tariff Pilots



Source: Faruqui and Sergici (2013).

and cross price elasticity of −0.10 (and −0.125 for Concession & Pensioner Households) with a load intercept of 0.55.[23] The former is applied to all households consuming more than 2500kWh per annum while the latter is applied to *all* households.[24]

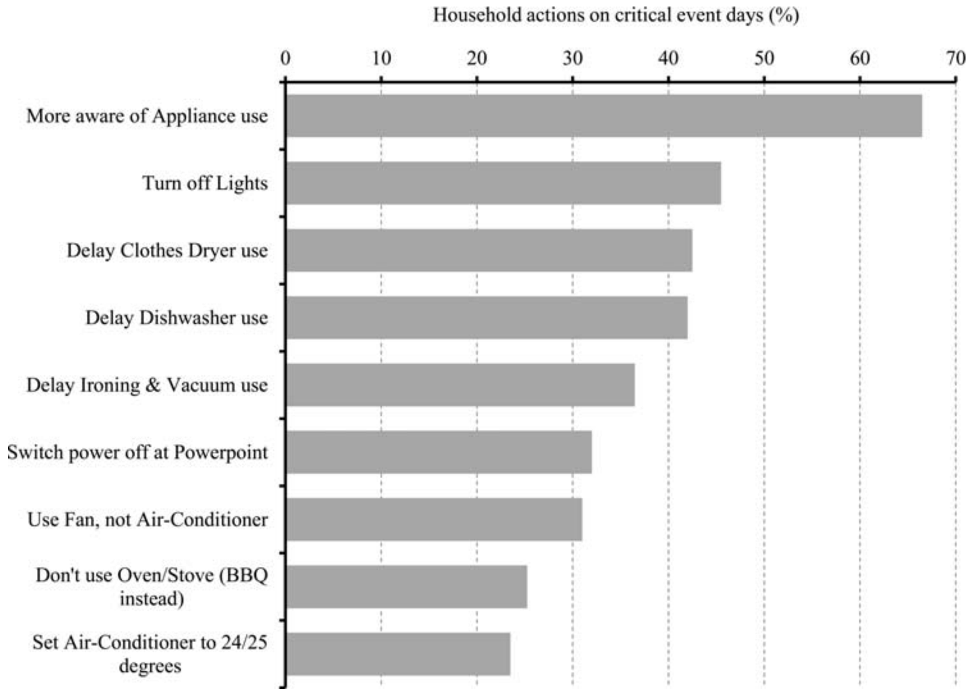
IV. TARIFF EQUALISATION MODEL

In order to produce a generalised view of the cross-subsidies under existing two-part tariff structures, we utilise AGL Energy's *HANA* and our Tariff Equalisation (TE) Model. This enables us to compare the annual charges of each household under the existing tariff structure with any alternate design. The underlying objective of the TE Model is to identify inter- and intra-segment cross subsidies subject to the constraint that regulated network revenues are equalised (i.e. through

23. Given our load intercept of 0.55, this results in critical event load shifting of *ca*19%, peak load shifting of *ca*5% and a conservation effect of 2% per annum. For Concession & Pensioner Households, load shifting rises to 24%. In our initial modelling results, we used a uniform elasticity estimate however on advice from an anonymous reviewer, we were encouraged to differentiate elasticity estimates if possible. Applied results from Energex & Ergon (2014) were used in our differential estimate for Concession & Pensioner Households (and uniform elasticity estimate results for this cohort can be found in footnote 28).

24. We note that the results from Figure 8 (and Energex & Ergon 2014) reflect a set of electricity customers who have 'opted-in' to a pilot study, and that we have uniformly applied these results across a much larger consumer base on a uniform basis. Consequently subsequent modelling results may well reflect an outer-limit to Demand Response.

Figure 9: Reported Behaviour of Households on Critical Event Days



Source: Energex & Ergon (2014).

network tariff rebalancing). To be clear, there are no static increases in transmission and distribution network profits arising from the change in tariff structures, while electricity retailers and power generators would face *marginally* lower net revenues after demand response.[25] By implication, total consumer welfare is unambiguously enhanced in our model. However, within cohorts there are winners and losers. Our TE Model is structured as follows:

Let H be the set of all households specified in the model.

$$i \in \{1 \ldots |H|\} \wedge h_i \in H \qquad (1)$$

Let P be the ordered set of all periods.

$$j \in \{1 \ldots |P|\} \wedge p_j \in P \qquad (2)$$

25. As our modelling results in Section V reveal, we have adjusted tariffs to equalise short run network revenues, but have not adjusted tariffs to equalise generator or retailer revenues. We estimate short run negative impacts of 2.4%. Long run impacts have been set out in Simshauser and Downer (2012), viz. after a period of dynamic adjustment the industry would face more favourable load factors, more predictable plant run times, better thermal efficiency, lower price risk and more stable consumer prices.

Let z be the number of period types. Let I_1 be the set of periods comprising the evening peaks on all working weekdays (from 3pm to 9pm) excluding periods in I_4. Let I_2 be the set of non-peak daytime periods (known as shoulder periods, from 7am to 3pm and 9pm to 10pm on working weekdays, and from 7am to 10pm inclusive on non-workdays). Let I_3 be the 'the set of all other periods (known as off-peak') from 10pm to 7am each day. Let I_4 be the set of 'critical event' peak periods, from 3pm to 9pm on the 12 weekdays declared to be 'critical events'. Let I_{sp} be the set of 'Standard Peak' periods from 3pm to 9pm on all weekdays. Therefore:

$$P = I_1 \cup I_2 \cup \ldots I_z \,|\, z = 4 \tag{3}$$

$$I_{sp} = I_1 \cup I_4 \tag{4}$$

$$\forall k,m \,|\, k \neq m,\ k \neq sp,\ m \neq sp\ :\ I_k \cap I_m = \{\,\} \tag{5}$$

Let the number of Billing days be d such that $|P| = d \times 48$. Let q_{ij} be quantity consumed by household h_i in each period p_j. Let T_f^m be the fixed charge that applies to each day d, and T_v^m be the flat-rate variable charge that applies to quantity consumed q_{ij}. Let t_y^s be the smart meter variable tariff for period type y, and T_v^s be the ordered set time-of-use tariffs:

$$y \in \{1 \ldots z\} \wedge t_y^s \in T_v^s \tag{6}$$

Let function $\mathrm{T}_v^s(j)$ give the variable smart meter tariff for period p_j:

$$\mathrm{T}_v^s(j) = t_k^s, p_j \in I_k \tag{7}$$

To establish Total Revenues R_i^m under a mechanical meter regime with the conventional two part tariff comprising daily fixed change T_f^m and variable energy charge T_v^m

$$R_i^m = \sum_{i=1}^{|H|} (T_f^m.d + \sum_{j=1}^{|P|} q_{ij}.T_v^m) \tag{8}$$

To establish Total Revenues R_i^s under a smart metering regime:

$$Let\ R_i^s \equiv R_i^m \,|\, R_i^s = \sum_{i=1}^{|H|} (T_f^m.d + \sum_{j=1}^{|P|} q_{ij}.\mathrm{T}_v^s(j)) \tag{9}$$

V. TARIFF EQUALISATION MODEL RESULTS

Our primary objective is to analyse the extent of wealth transfers within and between household cohorts. We compare the annual electricity bills facing 160,000 households using two market products in Table 1, (1) the existing Default Tariff (i.e. flat-rate tariff), and (2) an opt-in Time-of-Use plus Critical Peak Price (TOU + CPP)—both of which are set within two-part tariff structures.[26]

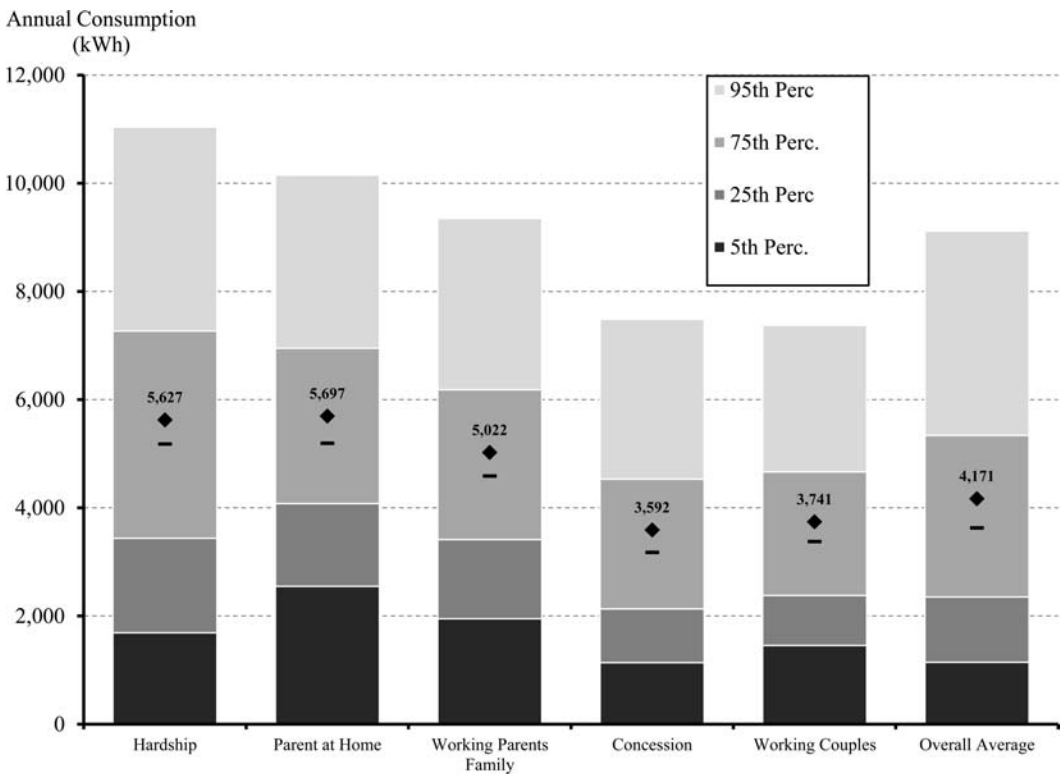
26. We estimate that more than 7.6 million of the 8 million households in Australia's National Electricity Market are on a flat-rate tariff similar to that outlined in Table 1 (i.e. being either on the default tariff product, or market contract which in which a discount has been applied to the default tariff product), hence its use as the initial benchmark.

Table 1: Tariff Structures

Tariff Structure	Unit	Flat Rate	TOU + CPP	Period
Fixed Charge	c/day	100	100	
Single Rate	c/kWh	25.9		All periods
Peak Rate	c/kWh		33.2	3pm–9pm Workdays
Shoulder Rate	c/kWh		25.6	7am–3pm, 9pm–10pm*
Off Peak Rate	c/kWh		15.6	10pm–7am All Days
Critical Peak Price	c/kWh		85.0	12 Days, 3pm–9pm

*Note that Shoulder Period includes Weekends: 7am–10pm
Source: AGL Energy Ltd (Based on a weighted average of two-part and TOU + CPP Victorian Tariffs)

Figure 10: Distribution of Annual Electricity Consumption by Cohort



Source: AGL Energy

In Section III, we presented average weekday household load shapes by cohort. However there is considerable variation within each cohort. Figure 10 attempts to illustrate this by presenting 5th, 25th, 75th and 95th percentile consumption levels along with Cohort Median (dash marker) and Cohort Average (diamond marker).

Given the default (flat-rate) tariff in Table 1 and cohort consumption in Figure 10, the corresponding annual electricity bills were calculated and illustrated in Figure 11.

Figure 11: Distribution of Annual Electricity Bill (Default Flat-rate Tariff) by Cohort

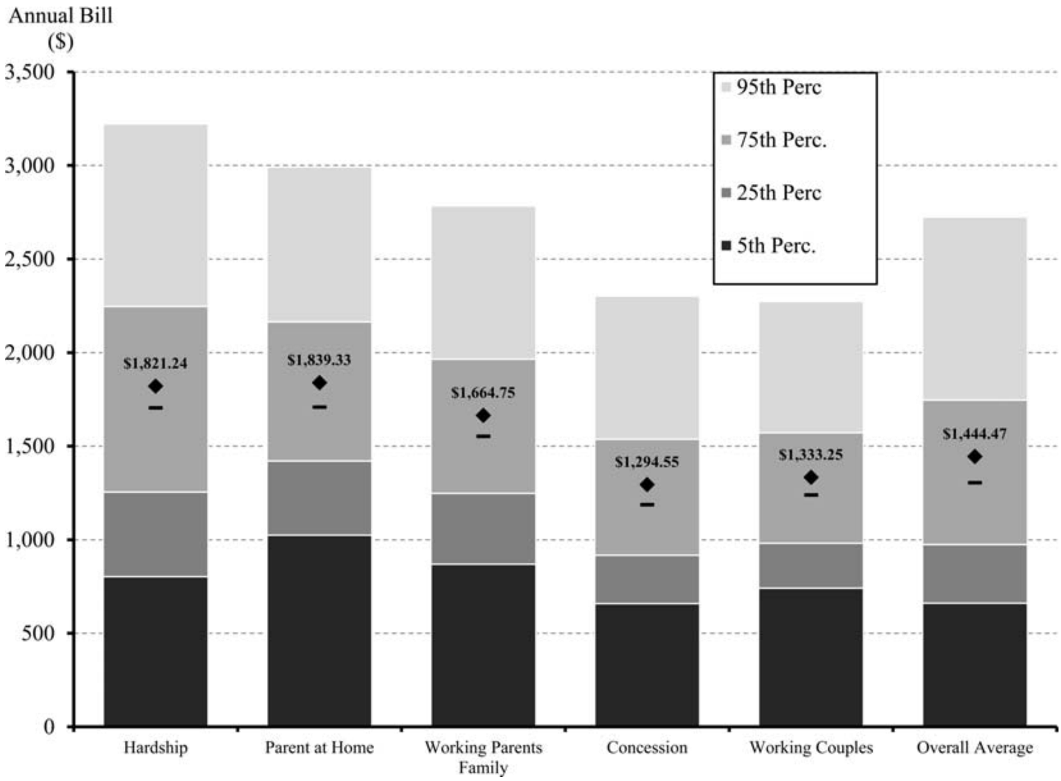


Figure 12 presents the first of our modelling results under more cost-reflective pricing and shows the distribution and intensity of wealth transfers amongst customers. There are two line series in Figure 12. Each presents the distribution of winners and losers after shifting from the default flat-rate tariff to Time-Of-Use plus Critical Peak Prices. The bold grey line is "All Households—*before* Demand Response". Notice that this line crosses the x-axis origin at exactly 50%. This means that all households to the left of the 50% mark are immediately better-off or *structural winners* on a Time-Of-Use tariff (i.e. lower left component of the propeller curve). The extent to which these households are better off is measured by the y-axis. The remaining 50% of households (to the right of 50%) are immediately worse-off or *structural losers*. Under flat-rate tariffs, it is these households that are being cross-subsidised. That is, they have higher peak loads than average and cause greater power system operating costs.

The thin grey line is the "All Households—*after* Demand Response". Here we apply our elasticity estimates (i.e. load conservation and load shifting effects) outlined earlier. This results in average household load reductions of *ca*19% during critical demand events, about 5% during standard peak periods and a conservation effect of *ca*2% per annum. Notice that the x-axis cross-over point shifts from 50% to 75%—meaning that three quarters of customers would eventually be better off once the tariff structure is understood and behaviour adjusts accordingly. However, 25% of customers would be *worse off*, albeit prior to network tariff rebalancing.[27]

27. Network tariff rebalancing requires that retail-level tariffs be increased by 1.4% (i.e. a 4.5% increase on variable rates charged by the networks, holding the fixed charge constant). This has the effect of shifting the cross-over point from 75% back to 64% as Figure 15 subsequently reveals.

Figure 12: Existing Tariff Inequities—All Households

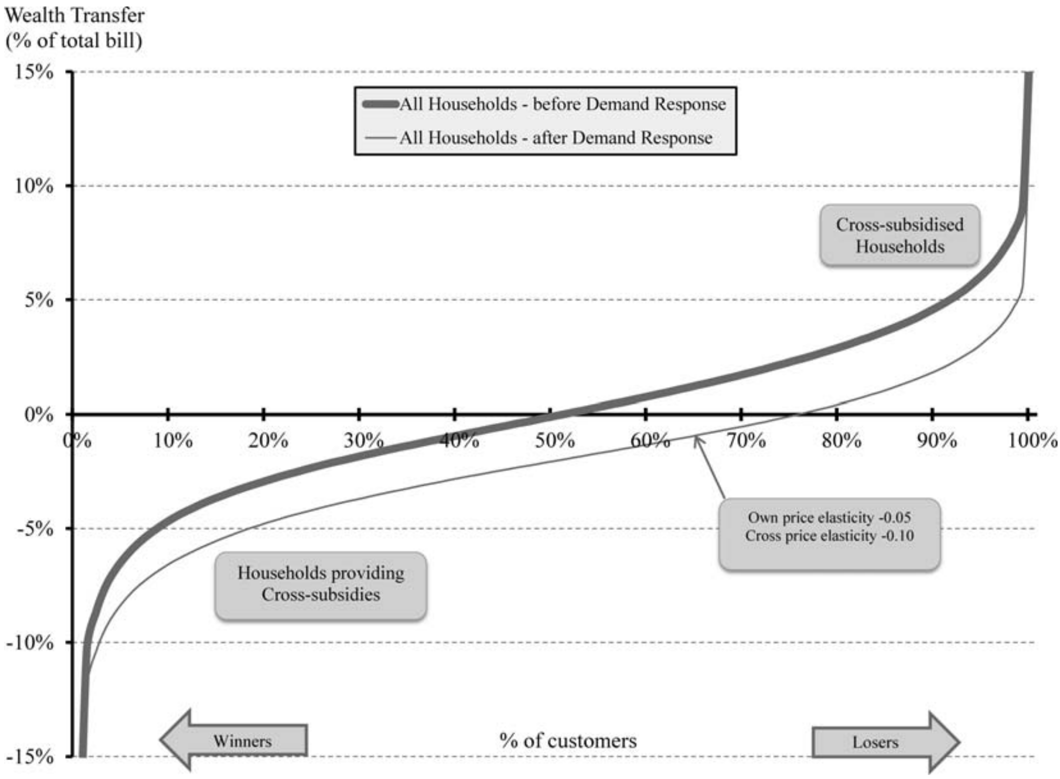
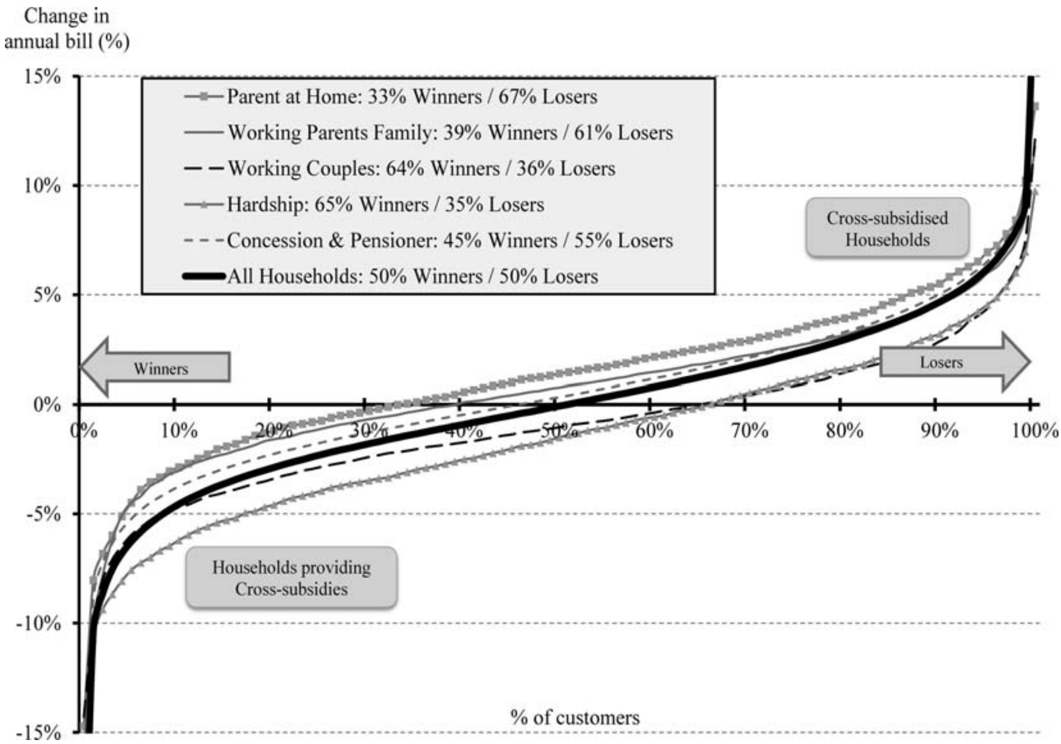


Figure 13 presents the modelling results for all household cohorts *before* taking into account the elasticity estimates outlined in Section III. In this instance, total industry revenues arising from the change in tariff design are equivalent and wealth transfers between, and within, the various household cohorts are identified. The results reveal that the largest structural winners by shifting to more cost-reflective tariffs are the 'Hardship' cohort with 65% better off. The reason that the Hardship cohort benefit so significantly by comparison to all other cohorts relates to their load curve. Recall from Figures 3–7 that the Hardship cohort had the 'flattest' load curve in comparative terms (see especially Figure 6). But to be sure, 35% of Households in Hardship are structural losers.

At the other extreme is the 'Parent at Home' cohort, with 67% structural losers and 33% structural winners. The Legend in Figure 13 identifies the mix of structural winners and losers for each cohort.

In Figure 14 we progress the results by applying our demand elasticity estimates. Given the reduction in peak load that follows, the cross-over points for all cohorts subsequently shift to the right and the Overall Average shifts from 50% to 75%. Prima facie this appears to produce an almost excessively favourable result. However, the Figure 14 modelling has not incorporated a rebalancing of network tariffs, thus the results reflect industry revenue losses of 2.4%. Additionally, as Borenstein (2013) found in similar simulations, *ca.*96% of households experienced annual bill changes of less than +/-10%. In this simulation, the largest winner cohort, Households in Hardship, moves from 65% to 87%, while the most prevalent loser in Figure 13, Parent at Home, shift from 33% to 67%. Concession & Pensioner winners move from 45% to 73% given their slightly higher

Figure 13: Household Segment Wealth Transfers—*before* Demand Response



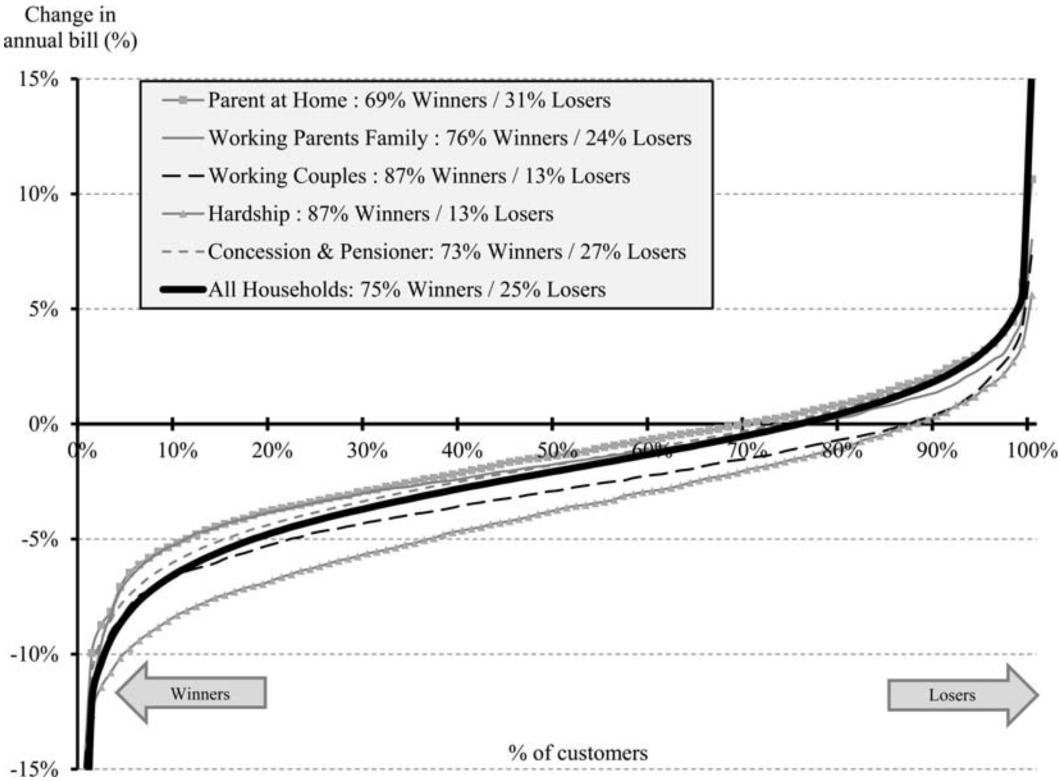
elasticity estimate. Note however that overall, 25% of households remain worse-off despite a Demand Response.

In Figure 15 we complete the analysis by rebalancing network tariffs to produce a revenue equivalent outcome for networks (but by implication, marginal losses remain within the competitive electricity retailer and power generation industry segments). Tariff rebalancing requires that variable rates associated with the network increase by 4.5% (or about 1.8% at the retail level), holding the fixed charge component constant. This has the effect of shifting the cross-over points to the left, with the Overall Average shifting from 75% back to 64% (note however that once again about 96% of households shift by no more than +/-10%). Our cohort that benefits most, Households in Hardship, now has 79% winners and 21% losers. At the other extreme, the Parent at Home has 54% winners and 46% losers.[28] Appendix I presents a variation to the Figure 15 results whereby network tariffs are rebalanced by increasing the daily fixed charge (rather than increasing the Time-of-Use rates). Similarly, Appendix II presents a variation by applying a long run elasticity estimate of −0.20 (compared to −0.10 in Figures 14–15).

The final set of results we examine (in the context of Figure 11) is the distribution of winners and losers by customer cohort in ‘dollar terms’. This is presented in Figure 16. This is another result which took us by surprise. While we had understood in percentage terms the prominence of ‘winners’ amongst Households in Hardship, we had not anticipated the extent of the

28. Note that the Concession & Pensioner result of 62% winners reduces to 58% if a constant elasticity estimate is used.

Figure 14: Household Wealth Transfers *after* Demand Response, *before* tariff rebalancing



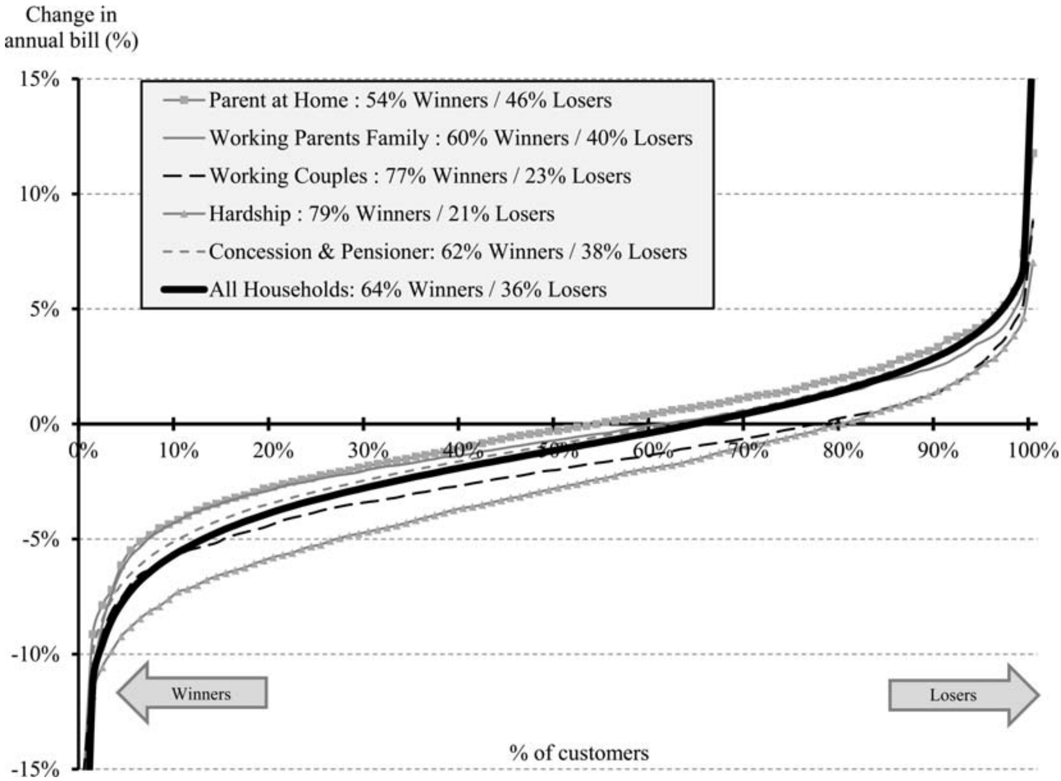
absolute dollar gains (or electricity account reductions) accruing to Hardship winners, and simultaneously, the small adverse financial impact accumulating to Hardship losers. Notice the pitch of the Households in Hardship propeller curve is considerably steeper for the winners, and flatter for losers, by comparison to all other cohorts and the Overall Average benchmark.

It is worth also briefly discussing the extremities of Figure 16. By comparison to the status quo, the 95th percentile 'loser' households in all categories *after* Demand Response and *after* network tariff rebalancing face bill increases of no more than 5% or \$58.40 per annum on average. However, the 100th percentile losers (i.e. top right hand corner of Figure 16) face electricity bill increases of up to 16% or \$440 per annum for very large consuming households. For clarity, of our 60,000 Concession & Pensioner Households, the 99th percentile group of customers (i.e. 59,600 customers out of 60,000) would experience a change of between -\$843.66 (winner) and + \$97.22 (loser) per annum. The final 600 loser households would face annual increases between + \$97.22 and + \$335.06. For all other cohorts, the equivalent 99th percentile results are a change of -\$982.89 (winner) and + \$137.18 (loser) per annum. The highest increase of any household was \$440.56 per annum.

VI. POLICY RECOMMENDATIONS AND CONCLUDING REMARKS

In our prior work in this area, we argued that the efficiency benefits of shifting to Time-of-Use tariffs included slower growth in peak demand, delayed or avoided network augmentation,

Figure 15: Household Wealth Transfers *after* Demand Response, *after* Tariff Rebalancing



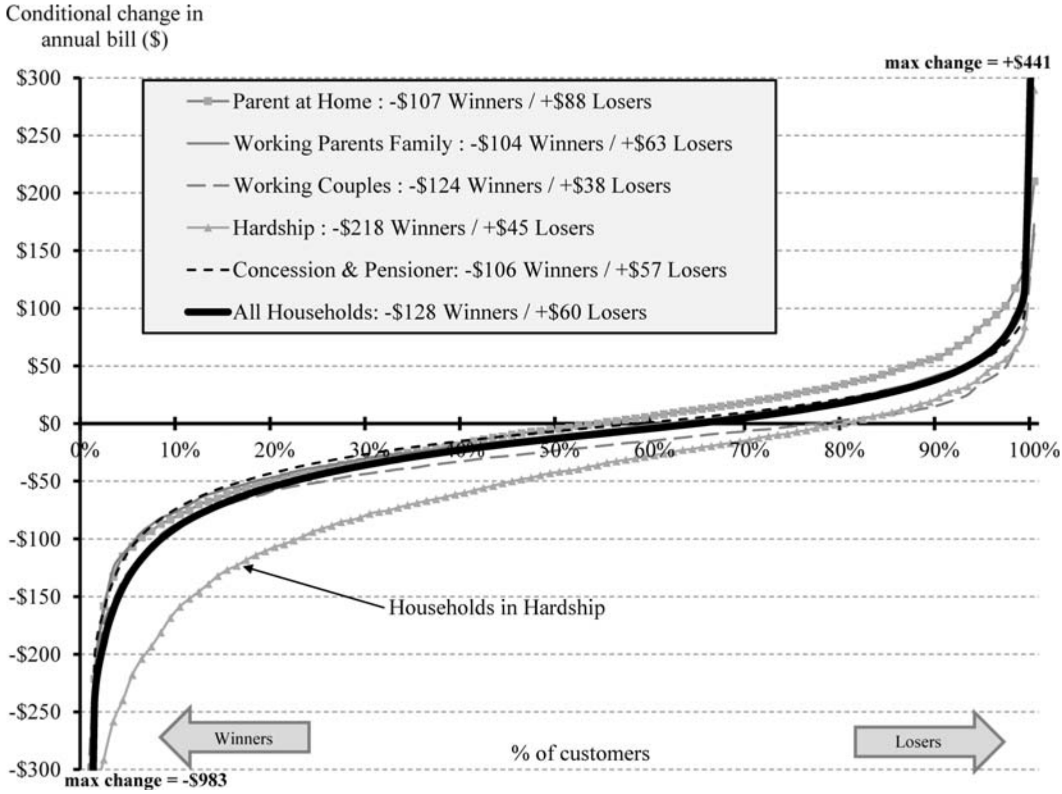
improvements to power system load factors, more predictable plant run times, an increase in the thermal efficiency of the plant stock, delayed requirements for costly peak load generation equipment and greater tariff stability (and therefore enhanced welfare). There will always be an extended period of dynamic adjustment in achieving such productivity gains, but our prior modelling revealed that over time those productivity gains could equate to as much as $1.6 billion per annum on the Australian east coast electricity grid (Simshauser and Downer, 2012). In the present analysis, we have argued that existing tariffs dominated by a flat-rate variable charge are inefficient and have demonstrated that they are inequitable. From an economics perspective, the case for default tariff reform is as clear as it is unremarkable.

But like most microeconomic reforms, structural winners and losers arise when benchmarked against (an inequitable) status quo. Accordingly, framing the case for reform is important. Energy costs represent about 2.6% of average household expenditure[29] and pales into insignificance by comparison to other essential goods and services such as housing (18%), food and beverages (16.5%) and transport (15.6%).[30] So in theory, tariff reform should be relatively straight forward in a stable cost environment.

Our objective has been to provide policymakers with missing evidence on the extent and intensity of existing inter- and intra-segment cross-subsidies. Our initial analysis showed that under

29. For households in the lowest income quintile, energy represents 4.0% of total expenditure.
30. See ABS (2011) 6530.0 Household Expenditure Survey.

Figure 16: Household Wealth Transfers *after* Demand Response, *after* Tariff Rebalancing



the existing default flat-rate tariff, up to half of the consumer base is being overcharged relative to their peak load, while remaining consumers are being cross-subsidised—simulation results that are consistent with Faruqui (2010a) and Borenstein (2013). The 'Parent at Home' cohort was found to receive the highest level of cross-subsidy. These cross-subsidies are essentially financed by 'Households in Hardship' and 'Working Couples' amongst others. Although to be clear, cross-subsidies occur within and across all segments.

Using our elasticity estimates, we found Demand Response was material during critical event days—reducing aggregate household peak load by 19%, on average.[31] And because the majority of that response was associated with load shifting rather than conservation effects, the impact on industry revenues was only −2.4% before tariff rebalancing. Once Demand Response was taken into account, all customer cohorts benefited considerably. We found that 75% of customers were better off, and even the cohort with the large proportion of losers (Parent at Home) reduced its losers from 67% to just 31%.

31. In an ideal world, critical peak products would be applied on a targeted basis at the network element level; applying to winter days for customers connected into winter peaking elements and to summer days for customers connected into summer peaking elements. In the era of Boiteux & Stasi (1952), such possibilities were simply ruled-out as technically impossible. But rapid advances in information system and telecommunications technology means that such products are far more than a theoretical possibility. Such innovative thinking should be encouraged by policymakers because if generalised, it will further maximise welfare.

For completeness, we analysed the impact of network tariff rebalancing which, given existing electricity network regulation in Australia, would be required to ensure regulated returns are met. To meet this constraint we increased network time-of-use rates by 4.5% (and retail-level variable rates by ca.1.8%) and held the fixed charge constant (and in Appendix I and II we varied the fixed charge and held time-of-use rates constant). Yet even after doing so, 64% of customers were better-off with the gains most prevalent amongst Households in Hardship, followed by Working Couples and then Concession & Pensioners. The Parent at Home cohort was split 54/46 in terms of winner/loser. At the extremes, relative to the status quo the 95th percentile 'loser' households *after* Demand Response and *after* network tariff rebalancing face bill increases of no more than 5% or $58.40 on average. However, the final 5% of losers, in some cases, faced increases up to 16% or $440 per annum.

Experience from US pilots indicates that where flat tariffs are the default product, less than 20% of customers will 'opt-in'. If more cost-reflective time-differentiated tariffs represent the product default, less than 20% of customers will 'opt-out' (Hoch, 2014). This suggests the structure of the default tariff is important. From an implementation perspective, how low income households are dealt with will clearly be important if their position deteriorates after reform. Smart meters enable more cost-reflective pricing, but they also facilitate accurate monthly billing. Mandating monthly billing should be considered an important log-rolling policy to aid household budgeting and minimise the incidence of bill shock. And to the extent that unwinding inter- and intra-segment cross-subsidies produces adverse outcomes for households poorly-equipped to accommodate the financial impact of such reform, Australia's *'tax and transfers system'* noted for its ability to provide targeted adjustment assistance, should be used. And ultimately, the electricity industry, policymakers and consumer groups must work together to ensure that the position of vulnerable customers (e.g. non-English speaking backgrounds, mental illness and so on) is optimised and that they are on the right product for their circumstances (Nelson & Reid, 2014).

We highlighted in Figure 1 that electricity tariffs have increased sharply since 2008. Simshauser and Laochumnanvanit (2012) demonstrated that sharp tariff increases have generated considerable (and understandably, adverse) media interest with coverage of the term *'electricity price'* experiencing a six-fold increase in regions of the National Electricity Market, from 1,654 articles in 2007 to 9,000+ articles in 2012. This heightened media was a product of Year-on-Year tariff increases at multiples of general inflation rates and the imposition of a deeply unpopular carbon tax. Consequently, the 'political will' to undertake tariff reform must have diminished. Even the Australian Energy Market Commission (2011) presented cautious advice on tariff reform by recommending that medium-size residential customers be able to 'opt-out' of default time-of-use pricing while small residential customers should be left on existing flat rate default tariffs with an option to 'opt-in' to time-of-use prices. In the absence of quantitative evidence outlining the extent and intensity of structural winners and losers, such advice represents a pragmatic approach to reform. As noted earlier, Borenstein (2013) provides policy prescriptions for an 'opt-in' approach by establishing two customer pools and shadow billing, which of itself would seem to create the conditions necessary for a so-called 'virtuous cycle' of customer participation.

In this article, we presented distributional efficiency impacts from restructuring the existing default flat-rate tariff to a Time-of-Use + Critical Peak Pricing structure, as outlined in Table 1. What we did not consider was other plausible tariff solutions such as a Demand Charge. As we highlighted earlier, given recent contractions in energy demand and the manner in which networks are currently regulated in Australia, a two-part tariff dominated by the variable charge component may become unstable if volumes continue to decrease. These are limitations of our analysis and are clearly important areas for further research.

With these limitations acknowledged, the most surprising result from our analysis of household winners and losers are those associated with the Households in Hardship cohort who are overwhelmingly better off after default tariff reform. A key issue for policymakers is, however, that households formally declared as being in financial hardship are typically a small percentage of the overall customer base. Simshauser and Nelson (2014) analysed approximately ¼ of the 8 million residential customers in the National Electricity Market and found that such households represent about 1–2% of the total. In their analysis a further 13–14% of households showed various signs of *potential* financial distress—with the median age of the household account holder being 44 years of age with larger than average electricity accounts. This tends to indicate that analysing the impacts on the Family cohorts (i.e. Hardship, Parent at Home, Working Parents Family) is important. What is less clear to us is whether the 13–14% of households identified in Simshauser and Nelson (2014) have load shapes closer to 'Hardship' (i.e. largest beneficiaries from tariff reform) or closer to 'Parent at Home' (i.e. largest losers from tariff reform). This also represents an area requiring further research.

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APPENDIX I: ADJUSTING FIXED CHARGES

In Figure I-a and I-b, rather than re-balancing network tariffs through increasing the variable Time-of-Use rates (per Figures 15 and 16 respectively), the Fixed Charge has been increased to restore regulated transmission and distribution network revenues. One would expect that ‘smaller than average consumption’ cohorts would be adversely affected by such a change. Smaller consuming cohorts include Working Couples (winners reduced from 77% to 70%) and Concession & Pensioners (winners reduced from 58% to 54%). Larger consuming cohorts were beneficiaries, including Parent at Home (winners increased from 54% to 56%) and Working Parents Family (winners increased from 60% to 61%). While Hardship in Households are high use consumers, winners reduced from 79% to 78% because they benefit more from the differentiated rates given their relatively flat (i.e. favourable) load shape.

Figure I-a: Household Wealth Transfers *after* Demand Response, *after* Tariff Rebalancing (Fixed Charge Varied to Rebalance Network Revenues)

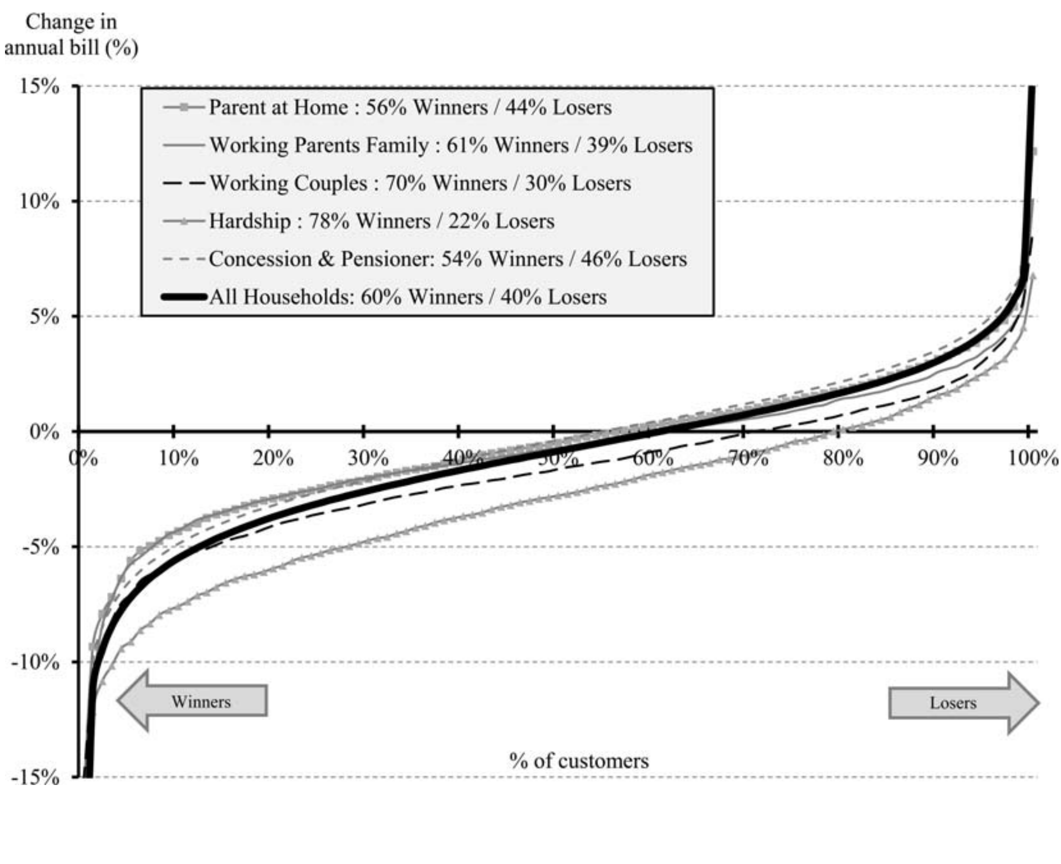
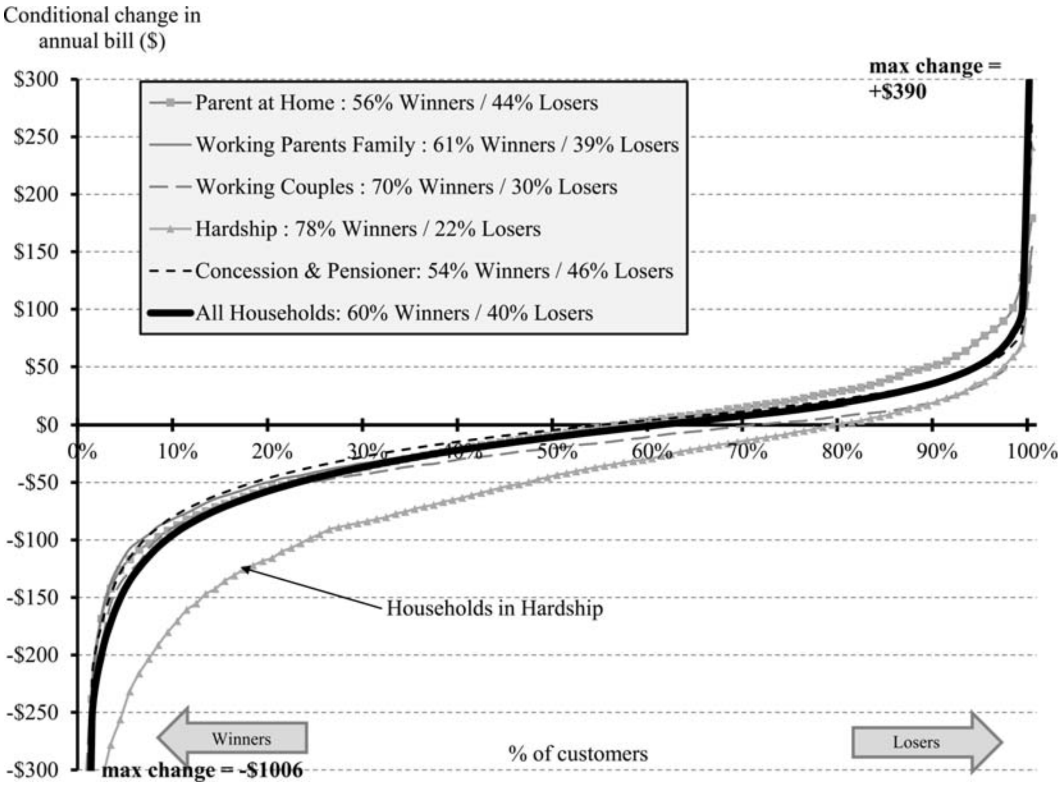


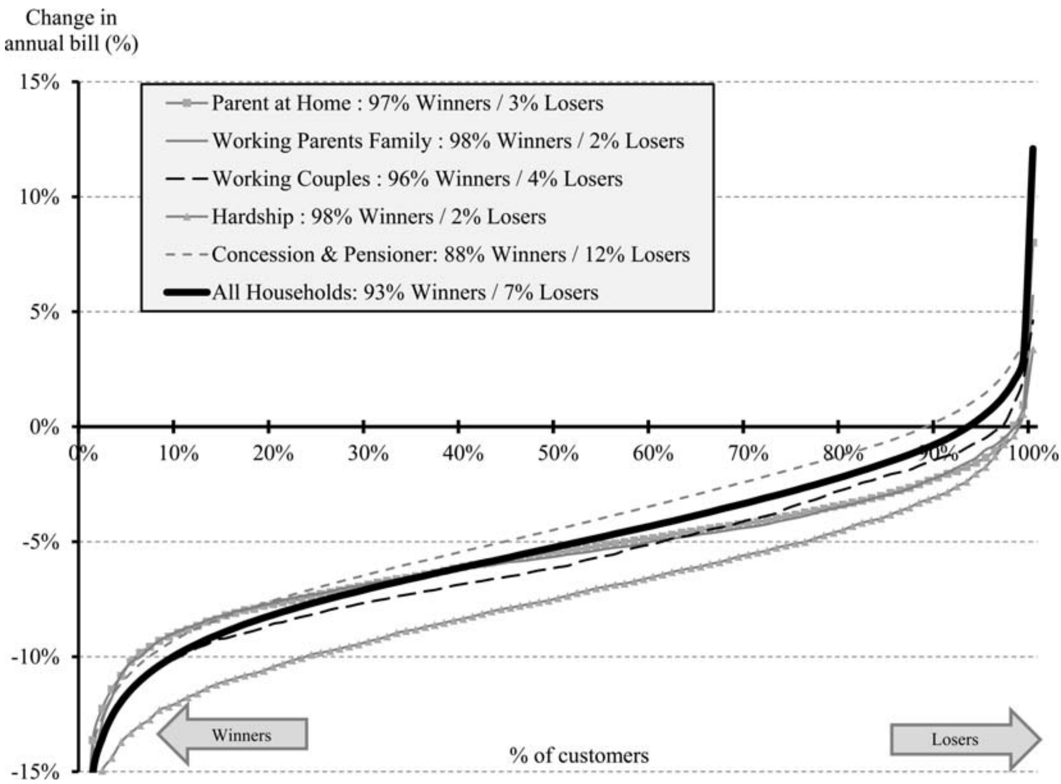
Figure I-b: Household Wealth Transfers *after* Demand Response, *after* Tariff Rebalancing (Fixed Charge Varied to Rebalance Network Revenues)



APPENDIX II: COMPARATIVE STATICS—ELASTICITY ESTIMATES

Figures II-a and II-b provide comparative statics for own- and cross-price elasticity estimates, having been increased to −0.10 and −0.20 respectively (effectively a doubling of the Demand Response captured in Figures 14–15). Given the sizeable reductions in peak loads, the crossover points for all cohorts shifts from 75% to 93% prior to network tariff rebalancing.

Figure II-a: Household Wealth Transfers *after* Demand Response, *before* Tariff Rebalancing



In Figure II-a we rebalance network tariffs (but to be clear, non-trivial losses would now exist within the competitive electricity retailing and power generation industry segments). The Overall Average shifts from 93% back to 71% (compared to 64% in Figure 15).

Figure II-b: Household Wealth Transfers *after* Demand Response, *after* Tariff Rebalancing (Fixed Charge Increased to Rebalance Network Revenues)