Introduction

This thesis examines public policy and economic implications of changing technologies in two key aspects of Australia's electricity system. Part 1 explores issues related to the retail supply of electricity in the context of technology evolution in metering, distributed generation, battery storage and in-home energy management systems. Part 2 of this thesis explores the regulatory and public policy implications of changing technologies through the prism of wholesale electricity markets, renewable energy and climate change. This introductory chapter provides some background on the Australian electricity market and attempts to place key propositions of the chapters (journal articles and published book chapters) in context.

The Australian electricity sector has undergone profound change over the past two decades. In the period between 1995 and 2005, it could be argued that much of the change was driven by microeconomic public policy reform introducing market competition for electricity generation and energy retailing. The Hilmer Reforms were promoted by governments and the electricity industry itself as having delivered significant savings for consumers through improvements in allocative efficiency (see Parer, 2002 and Abbott, 2002). Not all economists agreed that the reforms had produced real and lasting benefits, however, with Quiggin (1997), Quiggin (2001), Beder (2003), Chester (2006), Beder (2012) and Quiggin (2014) notable examples of dissenting viewpoints.

State Electricity Commissions had historically operated electricity systems within jurisdictional (i.e. state government) boundaries. As a result of the National Competition Policy (NCP) reform process established following the Hilmer Report, these Commissions disaggregated their power generation, transmission grid, distribution network and retail supply functions. In some states these newly created businesses were also privatised, but this occurred gradually. The economic policy rationale was simple – the introduction of competition in the parts of the supply chain that facilitated competition, and the use of economic regulation of network businesses to prevent monopolistic behaviour and pricing.

The reform of electricity generation and creation of the wholesale National Electricity Market (NEM) was a key microeconomic reform of the east-coast electricity market. NEM is often used interchangeably by policy makers to describe both the wholesale generation market and the overarching electricity system. The NEM wholesale market is an energy-only gross pool electricity market in which prices are formed under a uniform first-price auction clearing mechanism – put simply, prices during 'off-peak' periods tend to reflect short-run marginal costs of power generation, while prices at 'peak' periods can increase by around 25,000% to over $13,000 per megawatt-hour (MWh). In theory, this allows heavy fixed capital costs to be recovered over the business cycle.

Distribution and transmission network companies, or 'poles and wires' businesses as they are often referred to, are regulated monopoly infrastructure investments characterised historically by relatively stable financial returns on a highly capital-intensive asset stock. They entail a vast asset management and maintenance function with a focus on the efficient and reliable (physical) supply of energy to society. At the beginning of the reform period, much of the regulation of these businesses was undertaken by jurisdictional pricing regulators operating within state government boundaries. After 2004 and the implementation of undertakings made through the *Australian Energy Market Agreement*, these economic regulatory functions have been gradually transferred to the Australian Energy Regulator (AER) following its creation in 2005.

The end component of the reformed electricity supply chain is energy retailing. Energy retailers were created as customer-focused marketing and billing businesses, operating within a competitive pricing environment. Due to the significant potential fluctuations in wholesale pricing, these businesses have intense real-time energy commodity market exposures associated with purchasing electricity and they manage the associated risks on behalf of customers. The introduction of competition was staged through a scheduled timetable to ensure an orderly transition. Large commercial and industrial customers were made contestable immediately, with the introduction of 'full retail contestability' (FRC - whereby all customers including households could choose their retailer) gradually implemented on a jurisdictional basis. In the NEM, this process commenced from the mid-1990s, and was completed in Victoria and New South Wales in 2002, South Australia in 2003, and Queensland in 2007. Pricing deregulation was only implemented after competition had been deemed 'effective' as determined by the Australian Energy Market Commission (AEMC) under the *Australian Energy Market Agreement*.

The microeconomic reform of domestic electricity markets was not unique to Australia with many other nations undertaking comparable reforms at a similar time (see Pollitt and Haney, 2013). The popular policy objective underpinning such reforms relates to improvements in capital allocation and pricing efficiency. But energy policy requires broader objectives to be considered, a point well made by Simshauser (2014a, p. 550): '*The objectives of energy policy are to: (i) ensure the security of energy supply; (ii) with supplies delivered at minimum cost; and (iii) subject to an environmental constraint. Each of these policy objectives collides.*

Policy-makers must continuously trade off each at the expense of others.' In many ways, the NEM reform process of the late 1990s focused almost exclusively on the second of this three-point taxonomy.

From the early 2000s, it became clear that the NEM reform process had not adequately considered community expectations around anthropogenic greenhouse gas emission reductions and the development of new generation technologies. A proliferation of new public policies aimed at encouraging the adoption of new supply options with lower greenhouse gas emission profiles added significantly to the existing generation capital stock. These technologies have a distinctly different cost profile structure to existing and competing thermal (coal and gas) units. Fuel is effectively free (i.e. wind and sun) but with materially higher up-front capital costs. At a peak, there were six policies in place to drive capital substitution or addition, including: the NSW Greenhouse Gas Abatement Scheme (GGAS); the Large-Scale Renewable Energy Target (LRET); the Small-Scale Renewable Energy Target (SRES); the QLD 18% Gas Scheme; various energy efficiency policies (e.g. Victorian Energy Efficiency Target or VEET); and premium solar feed-in tariffs (PFiT). A carbon price was also established through the *Clean Energy Future* package but then repealed within a three-year window.

Chapter 8 provides a detailed assessment of the type and volume of new generation added to the system as a result of policies aimed at reducing greenhouse gas emissions. From a standing start, nearly 3,500 MW of new wind capacity has been added and the first of several planned large-scale solar plants were commissioned in 2015 (Nyngan and Broken Hill). Distributed generation has been even more prolific with around 4 GW of new capacity connected to the system and well over one-million households are now producing at least part of their own power requirements. This ‘energy revolution’ has profoundly changed the way in which many consumers view energy supply.

The second aspect of energy policy that some may argue was neglected by policy makers relates to energy security and reliability. Sydney experienced blackouts in its central business district (CBD) in 2003 and there were a series of distribution network-related blackout events in South-East Queensland (SEQ) in the first few months of 2004. As a result of these events, policy makers sought to tighten standards. They shifted from ‘probabilistic risk-based’ electricity network planning to a ‘deterministic N– 1’ methodology. The tightening of these standards led to a large increase in capital spending on electricity networks. Total network assets in some states more than doubled from $27.6 billion to $60.8 billion (see Chapter 9). Higher standards necessitated increased spending on networks, but the extent of the subsequent increases is cause for concern. Increases in peak demand would add to spending needs, but peak demand had increased only by around two percentage points per annum in each jurisdiction. It is implausible to suggest that such growth would justify a doubling of the network capital stock. Quiggin (2014) explores the manifest failures in the regulatory framework that led to this situation, but put simply, it may be suggested that policy makers overreacted to reliability and security of supply concerns by implementing measures that allowed electricity networks to ‘overspend’ relative to what was required.

The deployment of new technology and a global trend towards reduced greenhouse gas emitting large scale energy production is changing the way in which energy production and consumption occurs. Public policy reform is necessary to ensure that social and regulatory systems keep pace with the technological revolution underway. Pollitt and Haney (2013, p. 9) make the salient observation that when markets such as the NEM were liberalised, ‘competitiveness was the overriding priority. Today, competitiveness, energy security and decarbonisation are the three main energy policy priorities’. The evidence presented above shows that the Australian experience is consistent with this observation.

Electricity pricing reform has been focused on the wholesale market but it is end-user pricing reform that is critical for the uptake of new technologies. Between 2005 and 2016 the pricing reform process stalled. The continued use of old accumulation-style metering technologies, price regulation and flat ‘average cost’ regulated network tariff settings prevented meaningful retail product reform for much of this period. Air-conditioning penetration at the household level increased and system utilisation factors fell partly due to the absence of cost reflective pricing and retail product innovation. In Queensland for example, average demand increased by only 0.1% p.a. while peak demand increased by 2.1% p.a. from FY06 to FY14. Overarching NEM capacity utilisation fell from 54% in 2009 to 47% in 2014.

The absence of meaningful electricity metering and product market reform, together with divergent peak and underlying demand growth outcomes has created conditions akin to an ‘energy market death spiral’ (see Chapter 6). A ‘death spiral’ is described succinctly by Severance (2011, p. 13):

> *‘..a utility commits to build new equipment. However, when electric rates are raised to pay for the new plant, the rate shock moves customers to cut their kWh use. The utility then raises its rates even higher – causing a further spiral as customers cut their use even more. In the final stages of that death spiral, the more affluent customers drastically cut purchases by implementing efficiency and on-site solar power, but the poorest customers have been unable to finance such measures..’*

Evidence in Australia indicates that the NEM may have indeed experienced conditions akin to those described by Severance (2011) above. Appendix 3 outlines the significant increase in grid-based bills as prices roughly doubled yet average household consumption declined by 22%. In the Australian context, ‘average cost’ pricing of energy, not capacity, assisted with the uptake of solar PV and led to possible overinvestment in air-conditioning capacity (see Simshauser, 2016). A key theme of the ‘death spiral’ thesis is that pricing reform is important to facilitate efficient investment decisions in existing, new and emerging technologies through the creation of pricing arbitrage. This is particularly important as new technologies are acting as a ‘partial grid substitute’. Pricing reform should no longer be considered within the prism of ‘microeconomic reform’ but as a key element required to facilitate the efficient transition of a purely centralised electricity system to a bi-directional interconnected network that incorporates large-scale decarbonised energy production and embedded generation, storage and energy management systems.

From an end-consumer’s perspective grid-based electricity prices have increased markedly over the past decade. Household prices have risen by 10% p.a. from 2009 to 2013 following real price reductions in the two preceding decades (Simshauser and Nelson, 2013). Appendix 3 outlines how average New South Wales household electricity bills rose from around $1072 p.a. in 2007 to around $1660 p.a. in 2015. This occurred despite mean household usage declining by 22% over the same period from 7.5 MWh p.a. to 5.8 MWh p.a. As a consequence of such poor pricing outcomes many economists have concluded that there are clear weaknesses in the policy framework underpinning Australia’s electricity system. Quiggin (2014, p. 5) notes, ‘It is time to admit that the reform process, as a whole, has been a failure’ with shortcomings across: pricing; reliability; quality; efficient investment; and efficient operation.

This thesis is presented in two parts. Part 1 explores technology evolution and the implications for the retail supply of electricity. Over the past decade there have been significant advances in metering technology which have facilitated opportunities for creating new electricity tariff designs (see Chapter 2). New and innovative tariff designs are important not only for establishing conditions of allocative efficiency, but also for creating arbitrage opportunities for new technologies including distributed generation and storage (see Chapters 3 and 6). Such developments have the potential to reduce unit costs and greenhouse gas emissions. While technology has evolved, however, regulatory settings have remained focused on consumers purchasing their power from a centralised monopolistic grid. Regulatory settings need to evolve to facilitate a more efficient deployment of distributed energy, storage and energy efficiency. Consumers increasingly view their energy as multi-directional with production, consumption, energy management and storage all potential activities they can participate in (see Chapters 4 and 5). Regulatory settings must also consider the role of electricity as an essential service. Many consumers will face barriers to participating in markets for distributed energy resources for reasons such as split incentives (e.g. renting households), and policy and regulatory settings will need to address issues of affordability through adequate concessions frameworks and a focus on overcoming information asymmetry between energy companies and consumers (see Chapters 6 and 7).

Part 2 of this thesis explores the implications of changing technologies through the prism of wholesale electricity markets, renewable energy and climate change. As argued above, increasingly there is a disconnect between energy policy development and policy with objectives related to reducing greenhouse gas emissions (to address anthropogenic climate change) and increasing deployment of large-scale renewable energy. Policy-induced supply has been added to the electricity system and significant end-user price increases and energy efficiency policies have reduced grid-based electricity demand. While some generators have exited the market, there is still a large ‘overhang’ of capacity. Generators have been reluctant to permanently retire power stations due to both renewable policy uncertainty (see Chapters 8 and 10 and Nelson et al, 2010; Nelson et al, 2012a) and possible barriers to exit. All of this has occurred within a policy framework that has seen a carbon price introduced and then abandoned within three years (see Chapter 11) and the emergence of international pricing linkages for gas through the development of gas export capability in Gladstone, Queensland (see Appendices 1 and 2)[1]. The consequence of these developments is that policy maker attention has been sharpened on the design of wholesale electricity markets such as the NEM and there has been increased focus on related issues such as incumbent fossil-fuel generator barriers to exit and policy options to overcome them (see Chapters 8, 9 and 11 and Jotzo et al, 2015).

The rapid deployment of distributed generation and the emergence of battery storage has seen public commentary in Australia focused on innovation solely related to energy production and storage technologies (see the popular blogsite reneweconomy.com as an example). Such commentary has overlooked one of the most fundamental shifts in technology within the Australian electricity sector since the first generator was commissioned in Tamworth over one-hundred years ago[2]. Advances in computing and telephony technologies have led to the development of digital ‘smart’ metering capabilities that are now available to consumers at much lower costs. Without such metering technological evolution, the development of bi-

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[1] Historically, gas pricing on Australia’s east-coast has been based upon domestic supply and demand. The establishment of a gas export industry has resulted in a reduction in gas-powered plant utilisation factors within the NEM. This has had negative implications for GHG emissions as gas is a low-emissions substitute for coal.

[2] See Lobsey (1988) for the history of Australia’s electrification. Interestingly, developers of electricity systems did consider many of the tariff design issues relevant today but thought them too difficult to solve in the absence of advanced metering infrastructure.

directional interconnected networks with consumers acting as both producers, consumers and providers of services (e.g. storage, energy management) would be impossible. Quiggin (2014, p. 20) makes the salient point that, '...in the absence of sophisticated metering, electricity is a fairly simple commodity. Many households would have preferred to continue buying their electricity from the distributor [as opposed to a competitive retailer]'.

Chapter 2 explores some of the costs and benefits of amending the regulatory framework for metrology (metering) services. Historically, metering has been considered a key part of the electricity network and has been economically regulated as an element of the network's monopolistic infrastructure. Standard economic logic indicates that it would be far more efficient for a single entity to attend each home and business to read an accumulation meter – known as a Type 6 meter within the National Electricity Rules (NER). Such logic though, ignores a fundamental issue in restructured energy markets where distributors are structurally separated from energy retailers, namely, the potential for principal-agent information asymmetry and other costs to be incurred (Murtishaw and Sathaye, 2006)[3]. Within the NEM, distributors have been responsible for reading household and small business meters but the retailer is responsible for billing and ensuring the premise occupant provides 'access' to the meter. This creates obvious misalignment of incentives.

While the costs and benefits of shifting to digital meters for the purposes of introducing more elaborate tariff designs are relatively obvious, Chapter 2 considers whether introducing contestability for metering services would also improve these services by overcoming some of the principal-agent issues related to distributors reading electricity meters but not being responsible for billing and customer-facing interaction.

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[3] This problem has been known about at least as far back as Berle and Means (1932).

The analysis provides a compelling case for reform of the roles and responsibilities around metering within the NEM. Historical metering service quality has been poor – with one in thirteen meter reads wrong or erroneous. Given the development of new digital smart meters, it is reasonable to conclude that electricity customers should be free to appoint a metering provider of their choice. New smart meters are able to be read remotely and a contestable framework would facilitate greater customer adoption of new energy products and services such as distributed generation, energy management systems and storage. Customers would be free to select a metering provider that provides services best suited to their individual circumstances whether they be solely reliant upon the grid or a new 'prosumer' who both consumes and produces electricity. The AEMC has built on the recommendations of Chapter 2 by reforming the regulatory framework for metering through its Power of Choice review (see AEMC, 2012 for the original report).

The development of new metering technologies has shifted the view of policy makers in relation to tariff design. There are generally four types of end-user electricity pricing: 'average cost' tariffs that price electricity per unit of energy throughput (MWh); Time-of-Use (ToU) tariffs that price 'energy' but with rates that vary depending upon the time of consumption; capacity tariffs that price peak capacity demand (MW) rather than energy; and inclining/declining block structures whereby energy becomes more expensive/cheaper once a certain block of consumption threshold is reached. Each of these has advantages and disadvantages from a public policy perspective. While ToU and capacity tariffs may be seen to be more 'cost reflective' in that they facilitate pricing signals that reflect the costs of supplying energy/capacity to individual users, their complicated nature introduces potential for information asymmetry to be exploited in the absence of consumers being able to interpret them. On the other hand, flat ‘average cost’ tariffs tend to encourage overconsumption at system peak times and underconsumption at system off-peak times due to their non-cost reflective nature. Policy makers have a challenge to ensure economically regulated network tariffs, that comprise around half of the average household bill (see Appendix 3), are both cost reflective and understandable from a consumer perspective (see Stenner et al, 2015).

The absence of widespread time-differentiated pricing has been persistently identified as a limitation on efficient allocation of resources within electricity systems almost since their inception[4]. Avoiding a ‘death spiral’ is the most common thesis put forward as a reason for introducing more complicated ‘cost reflective’ tariff designs such ToU or capacity-based pricing. The literature is both extensive and diverse with many studies reaching the conclusion that more elaborate tariff designs are necessary. The following studies provide both theoretical and empirical support for such an argument: Boituex (1949), Dessus (1949), Houthakker (1951), Steiner (1957), Nelson (1964), Turvey (1964), Joskow (1976), Crew and Kleindorfer (1976), Wenders (1976), Faruqui & Malko (1983), Faruqui (2010a, 2010b), Faruqui and Sergici (2010, 2013), Faruqui, Sergici and Sharif (2010), Wood and Faruqui (2010), Faruqui and Palmer (2011), Simshauser and Downer (2012), Procter (2013) and Fenwick (2014). Most recently, Simshauser (2016) has provided quantitative evidence in relation to the Australian context. The study utilised evidence from Queensland to suggest that solar PV producers and households with air-conditioning are being subsidised through the persistence with ‘average cost’ two-part tariff design.

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[4] Inherent in this statement is the assumption of perfect information and competition. With these assumptions relaxed, questions arise around how consumers respond to more complicated tariff structures and their capacity to make consumption decisions in this context (see Stenner at al, 2015).

Chapter 3 expands upon the tariff design options outlined above. Specifically, a new tariff theory is proposed that essentially blends capacity and ToU structures to reflect a customer's load shape. Five principles for tariff assessment are listed: costs of shared network services should be apportioned to those users most responsible for the costs incurred; any changes in tariff structure should be revenue neutral for infrastructure providers; security of supply should be maintained; tariffs should provide pricing signals that facilitate customer behavioural responses (utilising appropriate technology such as home automation); and tariffs should be aligned with broader energy policy goals relating to reduced costs to society and lower greenhouse gas emissions.

The tariff model proposed shifts the focus from more elaborate tariffs being a function of time or capacity to a pricing model that incorporates both. By altering ToU pricing structures based upon the user's demand first derivative, customers are able to be rewarded for a flatter load shape which reflects greater utilisation of fixed resources. In practice, such a model would be almost impossible to implement as electricity consumers would not be able to respond instantaneously to pricing structures based upon the rate of change of their individual demand at any point in time. However, such a model could be simplified to reward those users who at times of peak demand do not increase their consumption and at times of off-peak demand maintain their consumption (where efficient for them to do so). Pricing electricity in this way would effectively result in a flatter overall load shape, reducing overall average costs of servicing the entire system.

The AEMC has mandated that all electricity networks within the NEM shift their economically regulated tariff structures to become 'cost-reflective'. Chapters 4 and 5 consider the role of network-proposed tariff redesign from a broader system perspective.

Peak demand across the NEM increased substantially over the past 15 years. In each jurisdiction, peak demand has grown by between approximately 20% and 40% (Australian Energy Market Operator: AEMO, 2015). While discussion has focused on more recent reductions in peak demand, the infrastructure required to service a level of higher demand is now in place. It is now questionable whether tariff reform is necessary at all to discourage further widening of the gap between peak load and underlying average energy demand. As an example, AEMO (2015) has forecast that grid based electricity demand in South Australia will be no higher in 2030 than it is today.

Policy makers need to question whether the objective of tariff reform is to either: discourage further expensive augmentation of the electricity system due to rises in peak demand (which the evidence indicates is now unlikely to be warranted); or to unwind current cross-subsidies through the production of solar PV, the use of air-conditioning and other activities which may result in users not bearing the costs they impose upon the system (see Simshauser, 2016). A further policy objective may be to reduce 'system unit costs' by encouraging demand at off-peak times but such a goal is likely to conflict with other objectives related to reducing emissions from coal-fired generation (see Chapter 11). The policy discussion is further complicated by the fact there are 6 NEM regions and 13 different electricity network 'patches'. There is currently no requirement for these network businesses to introduce similar tariff designs. Over time, this situation will undoubtedly result in inequity with electricity bills reflecting, at least partially, where the customer is geographically located.

Chapters 4 and 5 also consider the role of proposed network tariff redesigns for optimising the deployment of new distributed energy resources such as distributed premise-based generation, battery storage and energy management systems. At present, Keay et al (2014) find that, '..consumers are faced with confusing and perverse pricing signals.' As distributed generation has become more economic (relative to centralised supply options), utilities will need to adjust to a world in which grid-based electricity supply has a partial substitute. Tariff design has an important impact on the efficient uptake of distributed energy resources. Capacity tariffs will discourage installation of solar PV as the output from PV systems is generally non-coincident with a household's peak demand. Solar PV output is maximised in the middle of the day while household demand tends to peak in the late afternoon or evening, depending upon the customer's location and the climate, with peak load driven largely by spacial heating and cooling requirements. Capacity tariffs result in solar PV systems being less compelling because the output cannot be used to reduce grid-capacity requirements during the evening peak demand periods. Combined distributed generation and battery storage, on the other hand, is much more compelling for consumers facing capacity tariffs. This is because of the ability to shift distributed energy production into peak demand periods, reducing the requirement for grid-connected capacity.

In South Australia, Queensland and Victoria, regulated network businesses are proposing to shift their two-part 'average cost' tariffs to capacity based pricing within the requirement of the AEMC's mandate to introduce 'cost-reflective tariffs'. No doubt the commercial thinking behind this relates to restoring revenues lost through load reductions. Network revenue is a function of price and demand. As demand has fallen in recent years, networks have raised prices to keep them 'whole'. However, such thinking ignores that battery storage is emerging as an economic option for consumers. Major energy retailers and other businesses are now offering battery storage products. Chapter 4 demonstrates that households will view existing solar PV systems as sunk costs and a shift to capacity tariffs will create pricing arbitrage opportunities and incentivise the deployment of batteries and in-home energy efficiency and automation, resulting in a further loss of revenue.

Chapter 5 explores whether full grid substitution is possible for most residential customers. In Queensland for example, 26% of customers use 6-8 MWh of electricity with 35% consuming more than 8 MWh and 39% using less than 6 MWh. A 4 kW solar PV system produces approximately 6 MWh of energy. Even ignoring diurnal and seasonal variations in demand and supply, at least 60% of customers will be unable to fully substitute their grid-based supply with a combination of embedded PV generation and a battery storage system. Graham et al (2013) has estimated that the medium cost of disconnection from the grid is $0.47 per kWh – well above current average cost tariffs of between $0.25 and $0.30 per kWh. It is clear that policy makers and electricity utilities will need to consider how to design tariffs and business models to ‘coexist’ with the rapid deployment of embedded generation and emerging battery storage, at least in the short-term (Pieper et al, 2013). This will require careful consideration by policy makers. Tariff redesign is important as it may create opportunities for customers and businesses to generate electricity at lower costs to society. The network will be required to ensure reliability is provided for all customers. With less revenue as a result of partial grid substitution, such a condition may be violated in time without adequate foresight and planning.

It will be important for society to consider who should bear the cost of assets that are underutilised. On the issues of ‘stranded assets’, it could be argued that there is an implied social contract between society and regulated network businesses. Network businesses have been constrained from earning monopoly profits by economic regulation. It is an open question, then, as to the equity of subsequently exposing such businesses to competitive market losses incurred through technology innovation. Crawford (2015) provides some interesting perspectives on this issue. Irrespective of whether customers, governments or incumbent network businesses pay for reduced utilisation of the network, electricity supply businesses will need to consider new value propositions. Higher fixed charges, introduced to compensate for reduced throughput revenue, may in fact be acceptable to society if the alternative is reduced reliability. European utilities have stated, ‘future business models could be based upon future revenue per customer rather than volumetric supply’ (Citi Research, 2013, p. 34).

Retailers will also face an interesting dilemma in how to structure their ‘packaging up’ of network tariff costs into end-user pricing. Much of the discussion related to network tariff redesign *assumes* that retailers will ‘pass through’ tariff design structures. However, this may not be attractive to retailers and other businesses as they position themselves as the ‘Ubers’ or ‘AirBnB’ style businesses of the energy sector. These businesses could facilitate the trading of energy through the network between individual consumers utilising advanced information technology platforms and possibly even social media.

While tariff reform, metering and new technologies are critically important, Chapters 6 and 7 consider the role of electricity as an essential service. Electricity is rightly considered by the community to be a need, not a want, and policy should reflect this. Customers do not yet have a complete real alternative to grid-based electricity supply for modern necessities including lighting, cooking and spatial heating and cooling[5]. Australian policy frameworks broadly reflect this by placing special conditions upon holders of electricity retail and distribution licences in an attempt to minimise disconnections and the accrual of unmanageable

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[5] Consumer advocates also highlight the role of electricity as a means for social inclusion with employment and social interaction increasingly dependent upon information technology.

household debt. The policy framework, however, is not optimal and Chapters 6 and 7 provide several recommendations for reform.

The ‘average’ Australian household spends approximately 2.5% of their household income on energy bills. The use of averages, however, is always misleading when considering optimum public policy. Consumption of electricity varies significantly across household type. For example, Chapter 6 notes that mean consumption of households with income less than $34,000 per year is 6.03 MWh but 3% of these households use more than 12 MWh per year. As a proportion of household income, these households are spending approximately 10% on electricity. When such statistics are considered on aggregate, it is found that households earning less than $34,000 per year are paying approximately three times more of their income on electricity than households earning more than $130,000[6].

In recent years, Australia’s incremental housing stock has been among the largest in the world (see James, 2009) and air-conditioning penetration has increased to around two-thirds of households. It is unsurprising that household demographic cohort type has a material impact on energy usage and electricity bills. By blending demographic and electricity billing data, Chapter 6 shows that households within the ‘family formation’ bracket, with the age of the head of the household between 30 and 54, have higher average household energy costs than all other demographic cohorts, such as education and career formation (ages 20 to 29), empty nesters (ages 55 to 64) and retirees (aged above 65). In contrast, median weekly income per person per household is lower for the family formation cohort than many of the

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[6] This analysis of the distribution of energy costs by household income has important implications for the way in which government policy costs are incurred by households. Other studies have recommended that policies should be funded by progressive income taxation, rather than through energy bills (see Nelson et al, 2011 and Nelson et al, 2012b).

other cohorts. Put simply, households that use a lot of energy due to greater household size tend to earn less income per person.

Two key recommendations in relation to policy are presented in Chapter 6 on the basis of this evidence. Firstly, *if* electricity costs are one of the key household costs governments are attempting to address with any redistribution of income and wealth, support should be provided to those households within the family formation household cohort based upon *average* consumption. This could be done through increased payments for Family Tax style benefits. However, such an approach would ignore the widespread variation between household consumption and income. Concessions (i.e. electricity bill rebate) policies across Australia should therefore be harmonised as they are currently state-based and relatively unfocused. Rebates and concessions should be based upon need with eligibility criteria reflecting likely hardship. The amount of assistance, whether in the form of bill assistance or energy efficiency audits and the like, should increase in proportion to household consumption.

The retailing of electricity is contestable for all market segments across the east-coast of mainland Australia. Customers can choose a retail contract from three large ‘gentailers’ or more than a dozen ‘second tier’ retailers. Chapter 7 shows that there is significant price variation in the market with ‘discounts’ from ‘standing offers’ of up to approximately $1,000 p.a. for a household with average consumption. Regulated or ‘standing offers’ are generally set at the long-run marginal cost of supply. Given the significant oversupply of generation capacity and relatively low wholesale pricing of recent years (explored in Part 2 of this thesis), some commentators have suggested that retail pricing should be re-regulated (see Benn-David, 2015 as an example). Others have stated that markets are functioning effectively (see AEMC, 2015). The arguments for pricing deregulation are well made by Yarrow (2008, p.15) and he concludes: ‘price regulation in competitive market situations generally harms economic efficiency’. Johnston (2012) notes that in deregulated markets there is a greater variety of tariff shapes used by electricity retailers which ultimately benefits consumers with different consumption patterns. Even for those who argue that price regulation is necessary in traditional electricity markets, the development of economic partial grid-substitute technology such as embedded generation and storage has probably made the reregulation of retail electricity pricing quite difficult. Innovation is likely to be stifled by price reregulation. None of this overcomes the consumer detriment that occurs where firms use information asymmetry or consumer apathy to overprice an essential service.

Chapter 7 explores consumer awareness of electricity pricing and options for reducing electricity costs. Swadley and Mine (2011) demonstrate that greater customer participation and larger markets lead to lower prices. While many customers within the east-coast of Australia have entered into a ‘market contract’ with a discount from the ‘standing LRMC offer’, there are a proportion of customers who remain on higher tariffs. A significant problem for policy makers is overcoming the disadvantage being experienced by low-income and other hardship customers who are unable to actively participate in the market and reduce their energy bills. While consumer education and empowerment is an obvious policy tool, a ‘shared responsibility’ model is worth considering whereby the roles of industry, community and government are clearly defined and shaped by reciprocal obligation and incentives.

Part 2 of this thesis considers the implications of poorly coordinated electricity, climate change and renewable energy policies for wholesale electricity markets. The issues of climate change and capital substitution away from thermal generation to renewable technologies have not been well integrated through Australian energy policy. Australia has made several commitments through international fora to reduce greenhouse gas emissions in a manner consistent with global temperatures having a reasonable chance of not exceeding 2 degrees Celsius above pre-industrial times (IPCC, 2014). Australia's most recent commitment is to reduce greenhouse gas emissions by 26-28% below 2005 levels by 2030 (see Jotzo, 2015 for further detail on the target's comparability to other sovereign targets). It is clear that Australia does not have the policies currently in place to deliver on this commitment. In fact, many experts believe that such commitments will require a carbon price despite one not currently being in place. A 2012 survey revealed that 80% of respondents expected that a carbon price will be in place in 2020 (Jotzo et al, 2012) despite the fact that carbon pricing was such a politically volatile issue at the time.

As noted earlier in this Chapter, there have been a plethora of overlapping and competing climate change-related government policies implemented by governments that have fundamentally changed the way in which the wholesale electricity market functions. Given the commitments for 2030 noted above, this change is expected to continue. Since the creation of the NEM, there has been around 6,500 MW of new 'low-emissions' capacity (i.e. gas-fired generation) and around 8,000 MW of renewable capacity added to the capital stock. This investment has been driven by government policies unrelated specifically to energy but instead to climate change[7]. At the same time that this additional 'policy-induced' supply has come into the system, demand has materially declined after uninterrupted growth for the previous five decades. Saddler (2013, p.4) noted that demand fell by around 5% from 2009 to 2013 and that:

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[7] The most prominent of these policies is the Renewable Energy Target (RET) which is comprised of a 33,000 GWh large-scale renewable energy procurement obligation on electricity retailers (LRET) and a small scale deemed subsidy for solar PV and solar hot water (SRES). This policy is explored in detail in Chapter 10.

> *'If electricity consumption in the NEM had continued to grow from 2005 onward at the same rate as it had for the previous twenty, consumption would have been about 37 TWh higher in 2013 than it actually was. This difference is equal to the output of almost 5,000 MW of coal-fired capacity.'*

It is the combination of 'policy-induced' supply and declining demand that has most directly led to the inability of the 'energy-only' NEM to function properly. Chapter 8 explores these issues in detail.

In energy-only markets, generators receive payments for their energy but not their available capacity or reliability. The notion that competitive spot electricity markets are useful for matching supply and demand was first demonstrated by Schweppe et al. (1988). In theory, where aggregated discrete units of capacity (e.g. a 200 MW open-cycle gas turbine unit) exceed demand, prices are generally reflective of the short-run marginal cost (SRMC) of the marginal unit required to meet demand. However, where demand is met with the highest-cost final marginal unit, prices exceed SRMC outcomes, thereby allowing generators to recover their heavy fixed costs. This also facilitates new investment by providing pricing signals for additional capacity requirements. Where overinvestment occurs, prices do not allow for the recovery of fixed costs preventing further overinvestment occurring. Over the course of a business cycle it was expected that demand growth would absorb such overinvestment.

Like most areas of public policy, however, the real world implementation of these markets is impacted by constraints such as: regulatory interference; financial market considerations; and market price-caps (see Simshauser, 2008; Simshauser, 2010; Nelson and Simshauser, 2013; Simshauser & Ariyaratnam, 2014; and Simshauser, 2014b). In the Australian context, climate change-related policy uncertainty has also been problematic (Nelson et al, 2010 and Nelson at al, 2012a). Furthermore, regulators consistently attempt to artificially constrain energy prices within energy-only markets through the use of price regulation (Besser et al, 2002; Oren, 2003; de Vries, 2003; Wen et al, 2004; Finon and Pignon, 2008; Joskow, 2008; and Simshauser, 2010). The theory of energy-only markets also collides with the real-world incorporation of debt financing of significant sunk capital costs (Peluchon, 2003; Joskow, 2006; Finon, 2008; Simshauser, 2008; Caplan, 2012; Nelson and Simshauser, 2013; and Simshauser and Ariyaratnam, 2014). All of these factors have ultimately led many energy economists to conclude that energy-only markets are at risk of producing inadequate revenues to support continued investment in a 'least-cost plant mix' – also known as the 'missing money' problem (Bidwell and Henney, 2004; Neuhoff et al, 2004; de Vries, 2004; Bushnell, 2005; Roques et al, 2005; Cramton and Stoft, 2006; de Vries et al, 2008; Joskow, 2008; Simshauser, 2008; and Finon, 2008).

Chapter 8 builds on this existing criticism by establishing that energy-only markets cannot provide appropriate pricing signals for new investment and orderly replacement of the existing capital stock where assumptions related to continuous demand growth and the absence of policy-induced supply are violated. The existing theory of energy-only markets, in relation to new renewable energy investment, is put succinctly by Edenhofer et al (2013, p. 519):

> *'lower prices caused by higher renewable penetration lead to a reduction of overall capacity, which in turn increases the frequency of scarcity events and respective scarcity prices. According to theory this will bring the market back to the long-term equilibrium in which long-run average costs and average revenues are balanced for all capacities and where, as a direct result, the capacity level is efficient.'*[8]

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[8] Edenhofer (2013) is effectively rebuking the notion of a permanent 'merit-order effect' whereby low SRMC technologies such as renewables can reduce prices over the long-run. As Felder (2011, p. 34) notes: '*..if all*

There is an important assumption made by Edenhofer et al (2013) that is critical for energy-only market theory to be valid: incumbent inflexible thermal power stations retire permanently and are decommissioned. Evidence is presented in Chapter 8 which indicates such retirements are unlikely due to four possible barriers to exit: asset 'sweating'; first mover disadvantage; remediation costs; and policy uncertainty (see Nelson et al, 2010; Nelson et al, 2012a; and Chapter 10). The Australian experience, whereby 7,000 MW of excess capacity is still registered and available for dispatch, indicates that where conditions of demand growth and an absence of policy-induced supply are violated, these barriers prevent power stations from being retired, with the efficient functionality of energy-only markets being compromised. Over time, this may manifest as reduced system reliability and disorderly (as opposed to orderly) retirement and associated new investment. Such a situation would be accompanied by increased pricing volatility and is almost certainly unacceptable to policy makers.

To overcome barriers to exit three models are proposed: government funding; a market based mechanism; and regulatory closure. Jotzo et al (2015) have expanded upon these suggestions with a fourth option relating to industry-funded closure. Should governments proceed with some form of policy aimed at overcoming barriers to exit, Riesz et al (2013, p. ii) note that caution will need to be shown as, 'Payments for closure may create a vicious cycle that exacerbates barriers to exit'. If a closure policy is adopted in order to meet climate policy goals, policy makers must then reconsider whether an energy-only market design is appropriate given Australia's shift towards renewable energy. Caplan (2014, p. 33) discusses

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electricity was provided by out-of-market technologies wholesale energy prices would be near zero, yet consumer electricity costs would increase to cover the additional costs of these technologies, thereby indicating that there was something amiss.'

four market constructs aimed at overcoming ‘reliability challenges that are not adequately addressed by restructured wholesale electricity markets’ that are worth considering. At a high level, it is worth noting that a revised market will need to support investment in heavy fixed, but low operating, cost assets that are amortised over decades. Investments with these features are unlikely to be supported by investors if the main source of revenue is derived from a 30-minute spot market (and overlaid derivatives market) with extreme volatility.

Further evidence relating to changing wholesale electricity markets is presented in Chapter 9. As noted earlier, system capacity utilisation factors have plunged due to both underlying demand reduction (relative to peak demand) and the addition of new supply. The ‘death spiral’ concept has led to discussion around whether the gross energy-only pool design of the NEM should be adjusted to incorporate the ‘bidding’ of demand reduction. Demand-side response in electricity markets is well researched internationally. Masiello et al. (2013, p. 9) identified that the literature can be separated into two types: the utilisation of differentiated *retail* pricing to provide customers with opportunities for reducing or increasing consumption on the basis of pricing differentiated by capacity or time (as opposed to energy throughput); and the introduction of demand-side response bidding mechanisms in *wholesale* market design.

Chapter 9 considers whether demand response is best facilitated through differentiated *retail* pricing or adjustments to wholesale NEM design. In theory, if customers are already to be exposed to real-time wholesale market pricing fluctuations through time or capacity differentiated retail pricing (see Chapters 4 and 5), it would appear to be unnecessary to introduce demand-response bidding into the NEM. The analysis in Chapter 9 extends this by demonstrating there is a very low correlation between wholesale electricity market pricing and demand within residential networks, where load factors are poorest (and demand response potential may be highest).

Policy makers are better placed focusing on end-user metering and pricing contestability (as discussed in Chapters 4 and 5) as such policy reforms allow customers to reduce electricity costs by *shifting* consumption to lower than average pricing periods rather than just reducing demand per se. In theory, this would allow greater utilisation of existing generation and network infrastructure and a reduction in system average costs. Dynamic end-user pricing also allows for pricing signals to be used to incentivise consumption at times of low-emission energy production. As an example, such pricing structures could be used to increase consumption overnight when wind farm energy output is at its highest. By reforming pricing in this way, energy policy could be better integrated with climate change policy. Such conclusions cannot be reached in isolation of the limitations of consumer awareness of pricing (see Chapters 6 and 7).

To be clear, policy makers should be establishing ambitious emission reduction targets for Australia's economy and the east-coast electricity system. At the Conference of the Parties (COP) meeting of the United Nations Framework Convention on Climate Change (UNFCCC) in December 2015, all nations agreed to limit warming to two degrees Celsius above pre-industrial averages (UNFCCC, 2015). As noted earlier, Australia has committed to reduce emissions by 26-28% on 2005 levels by 2030. Given the commitment to achieving no more than 'two degrees' of warming, it is probable that such a target is inadequate. Assuming a linear reduction trajectory and a 'generous' share of a global carbon budget for Australia of around 10 gigatonnes of carbon dioxide equivalent between today and 2050, emissions may need to fall by up to 45% by 2030 (see Adams et al, 2015). The electricity sector will be a significant source of abatement as it comprises around one-third of Australia's national greenhouse gas inventory and other sectors may be unable to decarbonise within the same timeframe based upon current technology. For example, there are limited opportunities for reducing emissions in agriculture which is responsible for around 16% of Australia's national emissions[9]. Therefore, it is reasonable to conclude that the electricity sector *may* need to reduce emissions by even more than 45% by 2030. Such an outcome would result in significant transformation of the Australian electricity industry.

It is clear that Australia does not have the policy tools currently in place to deliver a 45% emissions reduction outcome by 2030. The Commonwealth Government has indicated that its platform for meeting emission reductions obligations are: a Commonwealth-funded Emissions Reduction Fund (ERF) which is allocated to emissions reduction projects through a centralised auction process; the Safeguards Mechanism that sets 'emissions baselines' for companies and penalties if these are exceeded; and the Renewable Energy Target (RET) which requires 33,000 GWh of new renewable energy to be procured from large-scale renewable sources by 2020. There are several limitations in relying upon this policy toolkit. Firstly, the ERF is unfunded beyond 2020. Secondly, the Safeguards Mechanism has not been designed in a way that results in emissions reductions, at least in the short-term[10]. Thirdly, the RET has been plagued by policy uncertainty with significant changes made to its operation in 2010 and 2015 despite it having only been introduced in 2001 and expanded in 2009. And finally, little attention is being paid to the integration of energy and climate policy (see

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[9] It should be noted that emissions from agriculture could be reduced rapidly if consumers shifted preferences away from meat and into grains and other plant based materials. There are limited *technological* opportunities for reducing emissions from livestock, a large source of emissions in the agricultural sector.

[10] As an example of the relative ineffectiveness of the Safeguards Mechanism, the electricity sector has been granted a 'sectoral' baseline whereby individual generation facility baselines are only 'activated' once the sector exceeds the maximum level of emissions of the previous five years.

Chapter 8). It is in this context that Chapters 10 and 11 consider the requisite policies for Australia to meet its emission reduction obligations.

Chapter 10 discusses the RET and the importance of policy certainty for climate policy more generally. Climate policy in Australia has been plagued by 'policy uncertainty'. The impact of carbon policy uncertainty has been quantified in two aspects by Australian and international economists: suboptimal investment decisions (see Nelson et al, 2010; Frontier Economics, 2010; Sinclair Knight Merz, 2011; Deloitte, 2011; and Nelson et al, 2012a); and suboptimal investment costs relative to a counterfactual scenario (see Simshauser and Nelson, 2012). On suboptimal investment costs, Simshauser and Nelson (2012) estimated the capital market efficiency losses associated with carbon policy uncertainty. Their project finance market survey established that providers of debt finance would impose higher risk premiums as a result of ongoing policy uncertainty in relation to carbon pricing. The higher risk premiums would result in capital market efficiency losses of up to $4.5 billion over the period between 2015 and 2020.

The capital market efficiency losses associated with policy uncertainty in relation to the RET are documented in Chapter 10. Due to the capital intensive nature of electricity generation, and in particular renewable generation[11], small changes in the risk premiums applied by investors to equity and debt financing of projects can have substantial impacts on overall project costs. Project financing market participants were surveyed to determine whether changes to the RET policy would change the risk premium priced into new infrastructure financing. A finding of this survey was that increased risk would be priced not only into new renewable projects, but other thermal projects. Amending public policy specifically aimed at

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[11] Renewable generation is almost entirely made up of up-front construction and financing costs as the fuel (wind, sun etc) is free.

developing new renewable energy results in heightened risk premiums being applied to the whole sector. When considered to 2020, these higher costs are estimated to add $119 million to consumer pricing.

The analysis in Chapter 10 is important given the public policy debate related to renewables and climate change in Australia. During the period between 2012 and 2015, there was a period of debilitating public policy uncertainty in relation to the RET. Two legislative reviews were conducted by the Climate Change Authority (CCA) and a separate review was commissioned by the Commonwealth Government and chaired by a prominent businessman who was alleged to have been a 'sceptic' in relation to accepting the science of anthropogenic climate change[12]. The Commonwealth Government subsequently reduced the target from 41,000 GWh of new renewable energy in 2020 to 33,000 GWh. It was posited that such a reduction was necessary due to declining demand resulting in a 41,000 GWh target being well in excess of the original 20% renewables target, and that the wholesale market could not support further investment without a reduction in the target. Unfortunately, little attention was paid to the interaction between energy-only markets, renewable energy targets and declining demand (see Chapter 8). Instead of reducing the RET, an alternative may have been to introduce a mechanism such as a carbon price or regulation to ensure older emissions-intensive plants were removed from the capital stock. Chapter 10 demonstrates that the consequence of these events is higher than necessary costs to society.

The future of Australian electricity and climate policy is explored in Chapter 11. Regulatory and market-based approaches are contrasted with different countries having pursued both and argued their superiority to each other. The theory is summarised well by Freebairn (2014) and

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[12] This review came to be known as the 'Warburton Review'.

Garnaut (2014), discussing the arguments for and against market pricing or subsidies as policy tools for achieving greenhouse gas mitigation. Based upon prior Australian experience, a ‘carbon price’ appears inherently difficult to implement given the intense political history related to introducing and then repealing the *Clean Energy Future* carbon price within a three-year period. Even if carbon pricing is implemented, Australian policy makers will need to consider whether such a scheme is ‘linked’ to other national schemes (e.g. the European Union ETS or a possible future Chinese ETS – see Jotzo et al, 2014). If the objective of climate policy is to structurally decarbonise the Australian economy, internationally linked carbon pricing may not result in emissions mitigation in Australia and may actually defer the structural decarbonisation of the economy (see Adams et al, 2014 for modelling that demonstrates this point).

Australia has much to lose, and potentially gain, through global action aimed at reducing greenhouse gas emissions. BREE (2012a, p. 1) estimates that Australia has 33, 10 and 2 per cent, of the world’s uranium, coal and gas resources respectively. Little attention is currently being paid to encouraging new technologies that would utilise these resources in a carbon constrained world. Chapter 11 postulates that specific climate policy for the electricity sector could be used more effectively to address this issue. It is recommended that policy makers consider: amendments to the existing RET policy to include all “zero-emission” energy sources (with subsequent international advocacy for other nations to adopt such a policy, thereby creating a deeper and more liquid market for new technology); new standards for power stations (as implemented in the United States); and regulations for incumbent plant retirement (as utilised in Canada)[13].

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[13] This final recommendation has been expanded upon by Jotzo et al (2015).

The conclusion of this thesis examines the electricity industry within an ‘evolutionary economics’ framework. Electricity has traditionally been a homogenous, essential-service good. Increasingly, many products and services being offered to consumers are heterogeneous as they can be tailored to suit the unique circumstances of individual energy users. While low-cost metering, distributed generation and emerging economics of energy storage are fundamentally changing the way in which consumers view their energy supply, the regulatory and social structures underpinning the industry have been lagging behind. In this author’s view, this can be explained by four characteristics of the energy supply industry globally which all result in significant inertia within the economic system: the contrast between the industry today and its historical stability and predictability; the capital intensive nature of energy supply; an aged workforce demographic within the incumbent industry; and the nature of the regulatory system the industry operates within.

Linearly evolving regulatory and social structures must be allowed to ‘keep up’ with technological change. There are three areas requiring attention: tariff reform; defining rules and responsibilities of market participants providing an essential service; and integration of electricity and climate policy, specifically a wholesale electricity market design that facilitates greater proportions of zero emission energy sources while maintaining system stability. The conclusion puts forward several policy principles for ensuring that the regulatory structure of Australia’s east-coast energy markets keeps pace with technological and consumer preference evolution:

- Integration of climate change and energy policy, and specifically a shift away from energy-only markets. Wholesale energy pricing should either directly or indirectly incorporate the externality cost associated with GHG emissions;

- Contestability, rather than regulation (in the absence of market failure), should be the starting point for development of roles and responsibilities within the energy supply chain;
- Competitive neutrality should be a cornerstone of policy development. Where entities have a competitive advantage bestowed upon them by economic regulation, appropriate ring-fencing should be in place to ensure that information asymmetry is not used to the detriment of consumers;
- National consistency should be prioritised. Australia is a Federal system of government and regulatory arbitrage is a key disadvantage of fragmented and differentiated policies across jurisdictional borders;
- Allocatively efficient (cost reflective) pricing should be mandated where entities are regulated. If distributed generation, storage and energy management systems lower the costs to society of energy supply, pricing should ensure such technologies are deployed;
- Appropriate consumer protections should be in place which reflect society's expectations around the role of energy as an essential service. These protections should apply uniformly to all companies marketing products where energy supply is the primary focus of their interaction with the consumer; and
- Technology standards should be robust and reflect guaranteed safe use of energy within the home and minimum levels of performance.

Future electricity systems will be considerably more customer-focused and decentralised than they are today. It is important that regulatory settings that were developed for a fundamentally centralised energy system with clearly defined market participants (generators, networks, retailers, consumers) are reviewed to ensure they are suitable for the future. To facilitate this market transformation, regulatory frameworks need to be technology-neutral and flexible to support a range of innovative new business models. Most importantly these frameworks should be focused on users of energy. As Smith and MacGill (2016, p. 380) state, ‘*Technologies will not shape the utility of the future – customers will*.’

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