Australian PV Association

A Distributed Energy Market: Consumer & Utility Interest, and the Regulatory Requirements

By

The Australian PV Association

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ARENA

Australian Government

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About the Australian PV Association

The APVA is an association of companies, agencies, individuals and academics with an interest in photovoltaic solar electricity research, technology, manufacturing, systems, policies, programmes and projects. Our aim is:

to support the increased development and use of PV through targeted research, analyses and information sharing

Our work is intended to be apolitical and of use not only to our members but also to the general community. We focus on data analyses, independent and balanced information and collaborative research, both nationally and internationally.

Our reports, media releases and submissions can be found at: www.apva.org.au

The results presented are for the purposes of informing stakeholders and the interested public. They are general in nature and subject to a number of underlying assumptions. As such, readers should not take these results as representing financial or investment advice.

Executive Summary

Key Points

- The ongoing uptake of Distributed Energy (DE) options such as solar PV, solar water heaters and energy efficiency are reducing electricity use and electricity utility revenues.
- This report proposes a regulatory framework that could form the basis of a DE market that would optimise DE's contribution to least-cost energy services and enable the existing electricity industry to transition to the 'new normal'.
- When 'disruptive technologies' such as PV and EE are introduced into a well-established industry, they don't simply integrate seamlessly, but exert change in doing so. Whereas the current electricity system is based on a 'top down' structure for consumers who simply buy electricity, DE is providing customers with a significant number of alternatives that allows them to actively participate in a system growing from the bottom up.
- To allow these two approaches to integrate requires a regulatory framework based on equal competition between supply-side and demand-side options at all levels (generation, networks and retail), for both network planning and during the day-to-day operations of the electricity market.
- Best practice Integrated Resource Planning (IRP) should become an integral component of network planning so that DE options can be used to decrease network expenditure. The proposed Regulatory Investment Test Distribution (RIT-D) is an embryonic form of IRP, but has significant scope for improvement.
- The market arrangements required to drive uptake of DE on a day-to-day basis can be divided into the following three types:
  - Those related to the operation of the incumbents: where the two most critical are decoupling network operators' revenue from their sales through the use of a revenue cap; and mechanisms that allow network operators to participate in the DE market, for example 'one-way' ring fencing.
  - Those related to the design and operation of the distributed energy market itself: for example, consumers should be able to source their electricity from, and sell their PV electricity to, entities other than their retailer; and solar access rights should be formalised.
  - Those that then stimulate the broader distributed energy market and enhance the interaction and operation of all participants: for example information and training, minimum energy performance standards, house energy rating schemes, and feed-in tariffs and white certificate schemes.
- To date, most effort has been on the third type of market arrangement, and as a result has been insufficient to effectively integrate DE.
- Once DE has been used to reduce network expenditure as much as possible, a proportion of network costs could be paid through a fixed daily charge based on a customer's monthly demand peak, making each customer's contribution to network costs more related to their impact. This approach is preferable to current suggestions of higher fixed charges for all customers, or specifically for PV customers, which would disadvantage low energy users and low-income households while also making price signals less cost-reflective.
- A fully competitive distributed energy market will need to develop over time, however, the required institutional and organisational changes need to begin now and will need to accommodate both the incumbents and new entrants, on an ongoing basis. DE technology is developing very rapidly and electricity utilities are likely to be left with stranded assets if regulatory processes are too slow to adjust.

Introduction

Residential electricity use in Australia has been declining each year since 2008/09, driven by a combination of factors including photovoltaics (PV), energy efficiency (EE) and responses to increasing prices (AEMO, 2013). Similar trends are being experienced in the US and elsewhere. The uptake of PV and EE is likely to continue and will put increasing pressure on utilities' income streams and business models. The responses by utilities and governments to date have essentially attempted to maintain the current business models, however, disruptive technologies such as PV and EE will likely drive the need for more fundamental changes.

This report discusses these issues and proposes a regulatory framework that could form the basis of a Distributed Energy (DE) market that would optimise DE's contribution to least-cost energy services and enable the existing electricity industry to transition to the 'new normal'. It is part of a collaborative research project funded by ARENA and the University of Arizona, from which separate reports will also be published by the CSIRO and the University of Arizona.

Electricity prices, demand & PV uptake

Residential and commercial electricity prices in Australia have increased significantly between 2008/09 and 2011/12, by on average about 40% nationally (DRET, 2012), with residential prices expected to increase further by about 7% per year out to 2014/15 (AEMC, 2013a). Network expenditure accounted for 50% of the increase from 2010/11 to 2013/14 (AEMC, 2011), and an expected 81% of the national increase in retail residential electricity prices between 2012/13 and 2014/15 (AEMC, 2013a).

Electricity use in Australia has decreased in absolute terms every year since 2008/09, with a total decrease of about 8,300GWh (5.5%) by 2012/13 (AEMO, 2013). AEMO has reduced the 2013/14 NEM demand forecast it made in 2012, by another 2.4%, although electricity use is still assumed to trend upwards in the near future, albeit at a slightly lower rate than previously estimated – see Figure 1. Residential and commercial electricity use per capita continues to decline, with total demand dependent on the accuracy of population growth projections (AEMO, 2013).

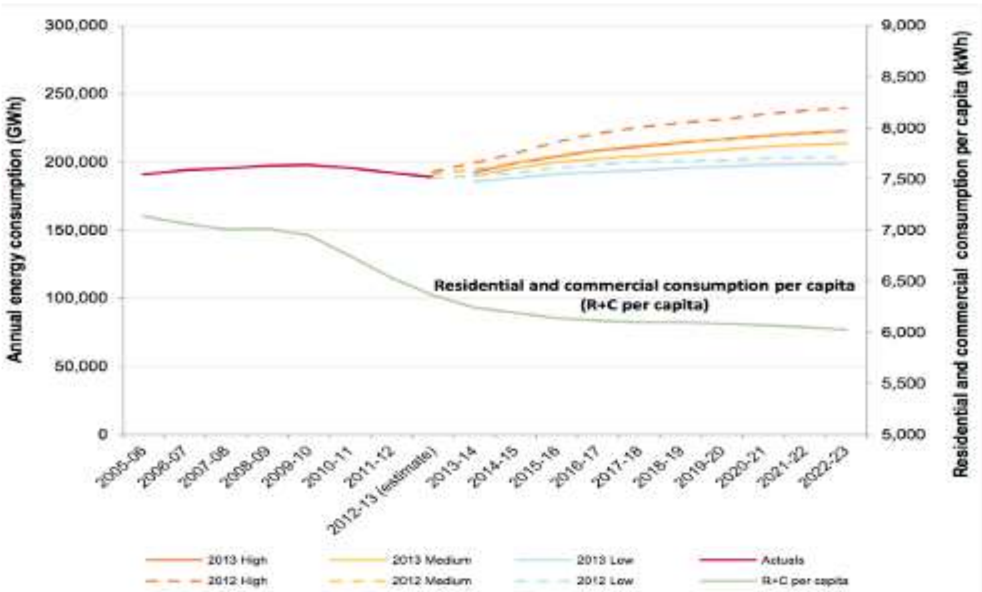


Figure 1. Comparison of annual energy forecasts made in 2012 and 2013 for the NEM under three growth scenarios (AEMO, 2013)

The decline in electricity use has been attributed to a range of factors, including lower GDP, reduced manufacturing, the uptake of PV, solar water heaters (SWH), and energy efficient technologies, as well as increasing electricity prices (AEMO, 2013; IES, 2013). Figure 2 shows the change in average residential demand in the Energex area of Qld from May 2009 to Jan 2013. It shows that PV-owners have significantly lower average demand that non-PV-owners, and there has been a steady decline overall (RE, 2013). As more customers take up PV it is clear that total sales will decrease further. A number of projections of PV uptake in Australia have been undertaken, over different timeframes and with different assumptions – where PV increases from the current 2.4GW to a range of 3GW to 14GW by 2020, and increasing thereafter (AEMO, 2012b; Lilley et al., 2013; Schleicher-Tappeser, 2013; Eadie and Elliott, 2013).

While it is impossible to accurately predict the actual level of electricity use in the future, should demand continue to decrease or even increase at a significantly lower rate than in the past, this would have important consequences for the electricity industry, especially network operators, which must cover the costs of past investment.

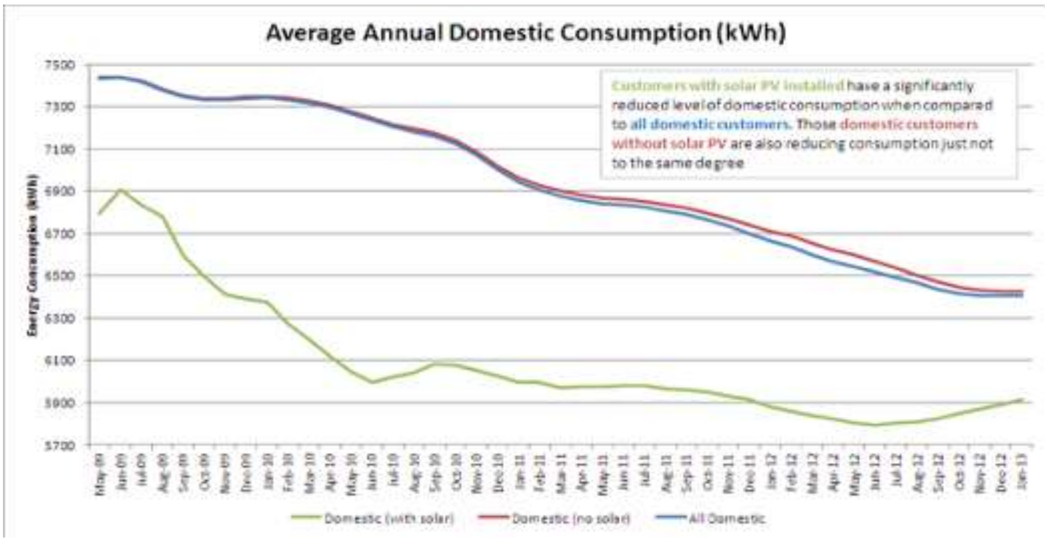


Figure 2 Energex residential demand with and without PV (RE, 2013)

Australian Consumer Interest in Distributed Energy Options

The Commonwealth Scientific and Industrial Research Organisation (CSIRO), with assistance from the APVA, conducted focus groups (FGs) that investigated the range of Australian stakeholder opinions and likely preferences in relation to opportunities for participating in distributed energy and demand side response activities (Ashworth et al., 2012). The analysis of these FGs was then used to inform a national survey, which was delivered across Australia in early 2013 (Romanach et al., 2013).

Participants were presented with six different technology options (Table 1) and four different payment options: Up front payment, hire purchase, solar leasing and energy service companies (ESCOs). A total of 18.3% of respondents owned PV systems and 11.9% owned SWHs. Figure 3 shows the composite score for acceptance of respondents who didn't already own these technologies. It can be seen that householders, on average, think that all the options 'sound like a good idea', and that they would consider installing both grid-connected PV and SWHs, and interestingly, grid-connected PV with batteries.

Table 1 Distributed Energy Options presented to the Focus Groups

Solar PV technology options		
Option	Solar technology	Abbreviation
1	Energy efficiency and solar hot water systems	SHW
2	Grid connected solar PV	SPV
3	Grid connected solar PV with battery	SPVB
4	Battery alone	BA
5	Community PV	CPV
6	Off grid PV systems with battery and generator	OG

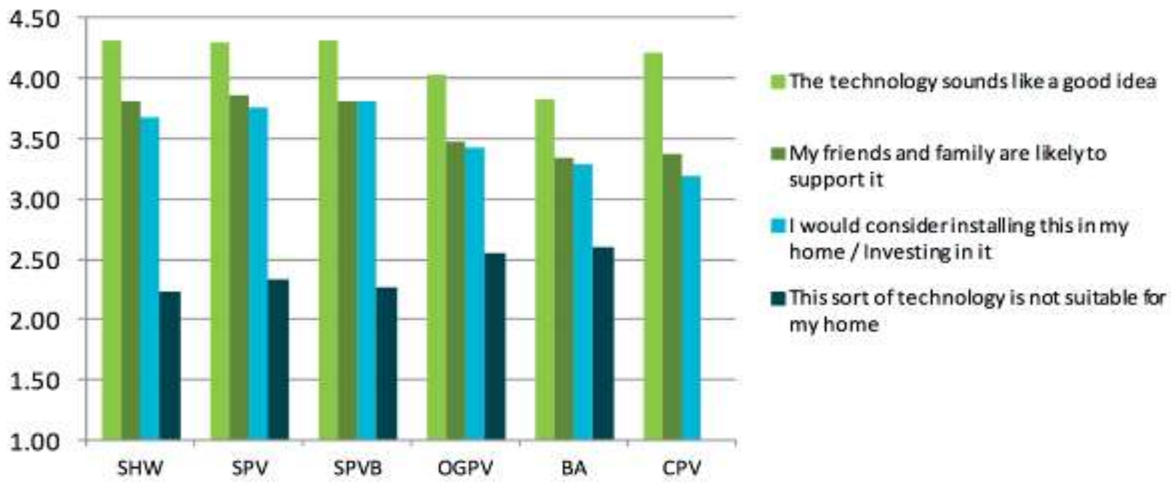


Figure 3 Australian household acceptance of DE technologies (respondents not already owning these technologies)

Cost savings are by far the primary driver for installation of PV and SWHs, and with the ongoing decline in installed costs of both PV and batteries, combined with the likely increases in grid electricity costs, the strength of this driver is likely to increase. Figure 4 shows the respondents' interest in different payment options for the DE technologies. There is a clear preference for paying up front, rather than using finance, leasing or through an ESCO.

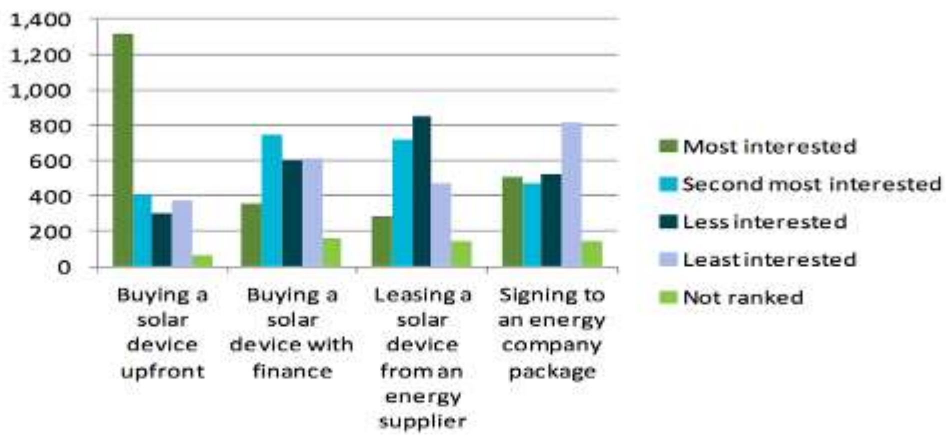


Figure 4 Australian household ranking of finance options to install or replace one of the technology options

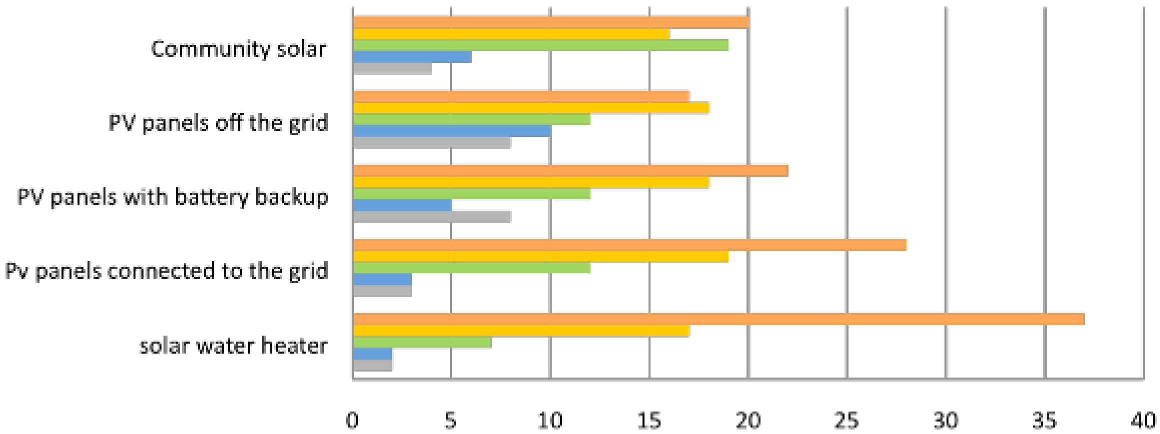
With respondents' being more interested in grid-connected PV with batteries than in batteries alone, it is likely that PV will drive the uptake of batteries. This would in turn enable the installation of larger PV systems and so further reduce electricity demand.

Mexican Focus Groups

Four FGs were conducted with a total of 65 people from the Mexican cities of Navolato, Culiacan, Mexico City and Guadalajara in March, 2013. Participants were presented with the same technology options as the Australian FGs, with the exception that the 'battery alone' option was not included. They were presented with three purchase options: Up front payment, hire purchase, solar leasing.

Prior to the FG, participants were asked whether they would consider installing any of the technology options. Their responses are shown in Figure 5, and it can be seen that the most preferred technology was solar water heaters, then grid-connected PV, followed by grid-connected PV with battery backup. The least preferred options were community solar, then off-grid PV.

These outcomes are remarkably consistent with those of the Australian survey, with the only difference being that, in Australia, grid-connected PV (with or without batteries) was ranked essentially as highly as SWHs. The Mexican relative preference for SWHs compared to PV most likely reflects their greater familiarity with that technology.



	solar water heater	Pv panels connected to the grid	PV panels with battery backup	PV panels off the grid	Community solar
Strongly Agree	37	28	22	17	20
Agree	17	19	18	18	16
Neither agree or disagree	7	12	12	12	19
Disagree	2	3	5	10	6
Strongly disagree	2	3	8	8	4

Figure 5 Mexican interest in installing a technology option (pre-FG)

Participants' preferences for the three purchase options are shown in Figure 6. There was a clear preference for financing through hire purchase, then buying upfront, then solar leasing. This is in contrast to the Australian results, where buying upfront was clearly the preferred option. As occurred in the CSIRO FGs in Australia, the participants' subjective knowledge of the different technology options significantly increased as a result of the FGs (P<0.05).

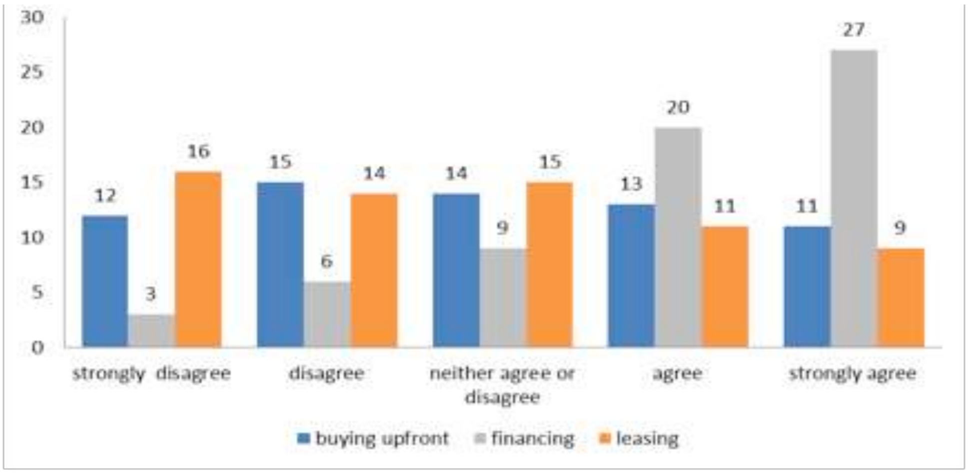


Figure 16. Purchasing preferences

Figure 6 Mexican respondents' ranking of finance options to install or replace one of the technology options

Consequences for Utilities

The reduced electricity demand has reduced income for wholesale generators, network operators and retailers. This trend is not restricted to Australia. For example, it is also occurring in the US (York and Kushler, 2011; Kind, 2013) and throughout Europe (Schleicher-Tappeser, 2013). However, under the current regulatory arrangements in Australia, network operators can adjust their tariffs to ensure that networks are paid for.

Figure 7 illustrates what has been referred to as a 'vicious cycle from disruptive forces' (Kind, 2013) and a 'energy market death spiral' (Simshauser and Nelson, 2012), where increases in usage charges reduce demand, which results in charges being increased again, which further reduces electricity use. According to this view, DE technologies will have a significant impact on utility revenue, and utilities that fail to adapt with new business models, products and services are unlikely to survive.

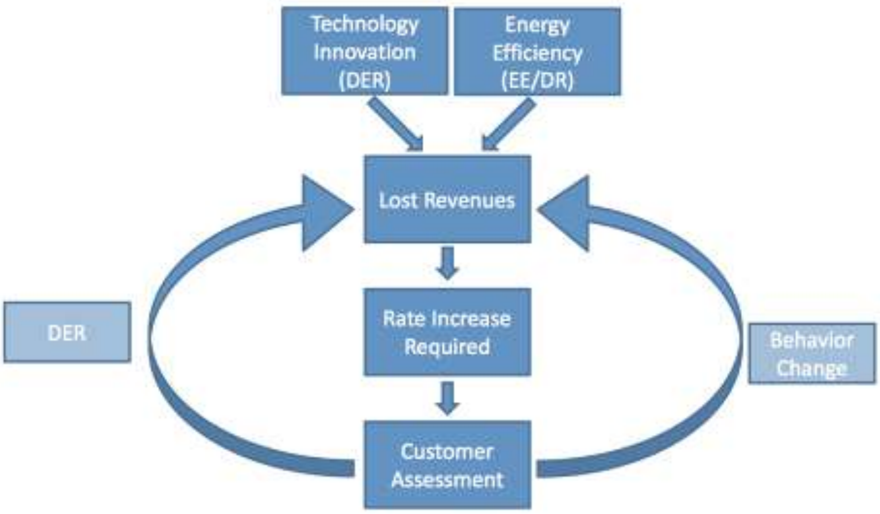


Figure 7. Vicious Cycle from Disruptive Forces (Kind, 2013)

Responses by Utilities and Governments

To date, there have been a variety of responses by government and utilities to reduced electricity use and increasing uptake of DE. Although there has been limited participation by retailers in providing DE, their responses essentially focus on maintaining the current types of revenue streams and business models, for example:

1. Implementation of TOU tariffs
2. Higher demand charges
3. Higher fixed daily charges
4. Low payments for PV export
5. Imposition of network limits on distributed generation.

Government responses have been more varied, ranging from those that attempt to directly reduce network costs for consumers and enable limited uptake of DE, to those that actively oppose DG options such as PV. They generally involve relatively minor changes to the regulatory environment. Two of the most relevant here are the Power of Choice (PoC) Review by the Australian Energy Market Commission (AEMC), and the Senate Select Committee on Electricity Prices. Both support cost-reflective pricing, information and increased competition, all of which should significantly assist the development of a distributed energy market. Another response from the Queensland Competition Authority proposes that gross metering should be compulsory for all PV systems, they be paid an optional rate of around 8c/kWh for all generation, and that all owners of PV systems should be placed on tariffs with high standing charges.

The reports are limited in three particular areas. The first is the very limited attention given to the consideration of introducing demand-side options into the network planning process, the second is the treatment of DG, EE and DSM as 'add-ons' to the existing market (which remains essentially unchanged), and the third is the lack of practical suggestions for decoupling network operators' revenue from electricity use.

The Need for Fundamental Regulatory Change

When 'disruptive technologies' such as DG, EE and DSM are introduced into a well-established industry (e.g. the Australian NEM), by their very nature, they don't simply integrate seamlessly, but exert change in doing so. Figure 8 highlights the fact that the conventional electricity industry is characterised by a relatively hierarchical structure, controlled by a small number of actors with a limited number of choices, and where customers could be treated as statistically predictable units. In contrast, DE is enabling end-users with a significant number of alternatives that is resulting in a system with much more self-organisation growing from the bottom up through a complex process (Schleicher-Tappeser, 2012).

Thus, minor adjustments of the system are probably not sufficient, and prudence requires preparation for unexpectedly rapid changes in a turbulent environment. Over the longer term, it is likely that much more significant changes to the electricity market will be required than apparently envisaged by the various government reviews.

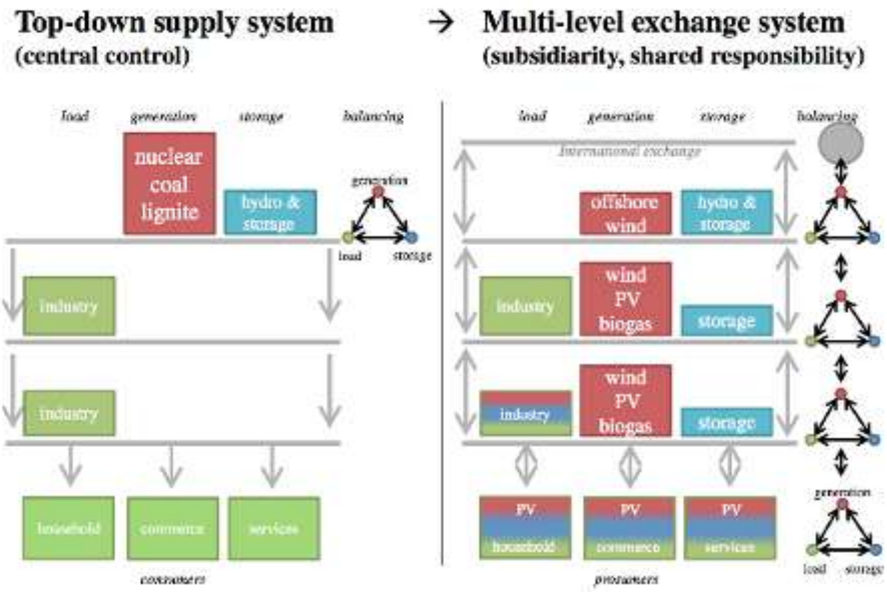


Figure 8. Transformation of the electricity system – schematic representation (Schleicher-Tappeser, 2012)

The Need for Full Competition in a DE Market

A fundamental principle of a distributed energy market is defined in this report as that of *equal competition between supply-side and demand-side options at all levels: generation, networks and retail*. There should also be competition between supply-side options and between demand-side options. For a distributed energy market these types of competition are illustrated in Table 2.

Table 2. Types of competition possible in the wholesale, network and retail markets

	Wholesale	Networks	Retail
Demand vs demand[1]	EE/DSM vs EE/DSM	EE/DSM vs EE/DSM	EE/DSM vs EE/DSM
Supply vs demand	Centralised and DG vs EE/DSM	Augmentation/capital replacement and DG vs EE/DSM	Electricity sales and DG vs EE/DSM
Supply vs supply	Centralised vs DG, DG vs DG	Augmentation/ capital replacement vs DG	Electricity sales vs DG, DG vs DG

The current Network Determination process essentially locks in network investments for 5 years, and so it is important that effective competition between supply and demand side options occurs during the network planning stage. In addition, in order for the market to be able to incorporate new technologies and to respond to changing circumstances over time, full supply/demand competition also needs to occur on a day-to-day basis in both the network and retail markets. This would allow 3rd parties to implement DE to manage loads at any time, and hence reduce the need for network expenditure at the next determination period. Thus, this report recommends establishing a DE market through:

[1] While DSM doesn't happen directly in either the wholesale or network markets, it does affect the operation of these markets.

(i) Proposing Integrated Resource Planning be used in the network planning processes, and

(ii) Driving full competition between all supply and demand-side options on a day-to-day basis.

Incorporating Integrated Resource Planning into the Network Planning Process

Integrated Resource Planning (IRP) can be used to formalise the incorporation of DE into the network planning and investment process. While there are variations on the IRP process (see Figure 9), the core principles are that it (Tellus, 2000):

1. Considers a full range of feasible supply-side and demand-side options and assesses them against a common set of planning objectives and criteria;
2. Is transparent and participatory throughout, meaning that parties other than the network operator can propose both supply-side and demand-side options;
3. Is subject to oversight by an independent (normally government) body; and
4. Is subject to regular review.

Thus, IRP can be used to identify areas where DG is cost-effective and requires the network operators to acquire it through a competitive procurement process. This helps to develop a competitive and transparent distributed energy market, and so opens it up to new entrants. This compares to the existing process for network augmentations where the network operator generally designs the default network solution, then possibly calls for alternatives, then assesses them through an internal procedure.

In addition to achieving least-cost outcomes, IRP can be designed to have a number of additional benefits. It can help achieve social and environmental objectives, reduce risk and volatility, provide more accurate network costs, because competition from third parties brings market forces to bear in the costing process, and so help restrict increases to the regulated asset base.

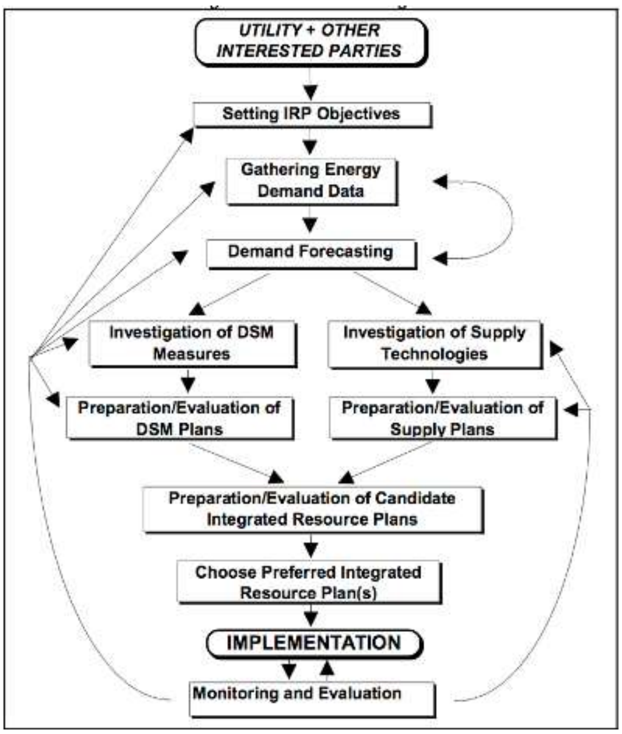


Figure 9. The Integrated Resource Planning process (Tellus, 2000)

RIT-D: IRP in Australia

During the course of this project changes were made to the National Electricity Rules (NER) that included the development of a Regulatory Investment Test for Distribution (RIT-D) that will replace the existing Regulatory Test for distribution investments. It is a basic type of IRP and will come into effect on 1 January 2014 (AER, 2013c).

It has a clearly stated aim and formalises the inclusion of non-network stakeholders, who are able to propose their own non-network options. It has a well-defined process that lists the minimum non-network options that must be considered, and requires a stand-alone Non-network Options Report. The requirements of the Draft Proposal Assessment Report are well defined: it must include all assumptions and the methodology used, and must conduct scenario and sensitivity analyses. It is open to scrutiny by all stakeholders, and is reviewed by an independent body, the AER.

However, currently the RIT-D does not need to be applied where the project is related only to the refurbishment or replacement of existing assets. There also appears to be no process to encourage the effectiveness of non-network solutions to be tested in advance. The RIT-D process also includes only economic impacts, excluding the potential social and environmental benefits listed above.

Still, with the RIT-D becoming operational on the 1 Jan 2014, and combined with regulation under a revenue cap (as discussed below), there should be a clear incentive for DNSPs to implement alternatives to network augmentation where they are cheaper.

Full Competition on a Day to Day Basis

The market arrangements required to drive full competition between all supply and demand-side options on a day-to-day basis can be divided into three types:

1. **Those related to the operation of the incumbents**

These in turn can be subdivided into those that decrease utility opposition to distributed energy and those that enable utility participation in distributed energy. The most critical example of the former is the decoupling of DNSP revenue from electricity sales through the use of revenue cap regulation. During the course of this project the AER announced that this would apply to the next network determinations that are due for assessment - both the ACT and NSW – and it appears that it will apply to all DNSPs in the NEM over time.

An example of market arrangements that enable utility participation in DE is where it is permissible for network operators to own and operate DE – however this could have anti-competitive impacts if DNSPs’ regulated revenue provides them with an unfair advantage over 3rd party providers. One option is that DNSPs could own DE assets that would then be made available to 3rd parties to operate on a competitive basis, and so competition would be introduced both when hardware was purchased and during operation (OG, 2012). However, DE options would be limited to those selected by the DNSP, and such options could have an unfair advantage over alternatives selected by 3rd parties. ‘One way’ financial ring fencing could be used to limit unfair advantages, whereby money can flow to the regulated monopoly from an associated DE business but not the reverse. Where the DNSP is regulated under a revenue cap, any profits from the associated DE business that are returned to the DNSP would place downward pressure on tariffs.

2. **Those related to the design and operation of the distributed energy market itself**

These measures focus on establishing an environment where different participants can compete fairly, including new entrant 3rd parties. For example:

(i) That consumers be able to source their electricity from, and sell their DSP to, entities other than their retailer (portability),
(ii) That the sale and supply of electricity be unbundled from non-energy services, such as ancillary services,
(iii) That third parties be able to provide energy services to residential and small business consumers,
(iv) That solar access rights be formalised,
(v) That price signals better reflect the cost of supplying electricity at specific times.

3. **Those that then stimulate the broader distributed energy market and enhance the interaction and operation of all participants.**

Once the market has been established, these measures enhance the operation of all participants (both incumbents and new) and so drive the uptake of distributed energy technologies. Policy measures to promote distributed energy can be broadly categorised into:

1. Support mechanisms such as the provision of information and training.
2. Command and control mechanisms.
3. Price mechanisms that change the energy ‘price’ seen by decision-makers for different energy options.

Responses by Utilities and Regulators to these Proposals

The Regulators’ opinions differed regarding electricity demand, with some believing it would stabilise and some thinking that growth would continue much as before. However, they thought the rate of network construction would slow significantly, with most effort going into capital replacement. There is a general view that tariffs are not cost-reflective, with the fixed component too low and the variable component too high. Although they expected PV uptake to continue, battery uptake is expected to be slow, with little interest currently evident from consumers or networks.

They were in favour of the market being opened up to as many players as possible to increase competition. However, they believe an evolutionary process is needed to get to a new regulatory model, and there is a need to change organisational culture.

Regulatory change is slow, with network determinations only reviewed every 5 years, and other adjustments only made after extensive review, and often subject to political agreement, and so will likely be lagging changes expected over the next 5 years due to continued uptake of PV, but also batteries, demand management and other new technologies.

Most utility respondents agreed that while energy and peak demand growth are difficult to predict, they would return to similar previous levels and that the recent softening was a short-term trend. They are considering different tariff structures and charges which offer some protection from the vagaries of energy demand and provide more predictable returns. There is a tension between the regulatory conditions which control price setting and the sovereign risk associated with returns for the State-owned entities. Lastly, there are complex human behavioural dynamics at play, which can result in short and/or long-term changes and skewed results.

Respondents thought that regulatory reform was needed to allow for a changing electricity environment. However, regulation for electricity utilities is Government controlled and is thus intrinsically linked to much broader political issues than just cost recovery and efficient operation. The majority felt that their roles were primarily restricted to operating their business and broadly advising on the ideal outcomes, but that ultimately political outcomes would determine regulatory conditions.

Most respondents felt that they already use some (varying) elements of Integrated Resource Planning, although there seemed to be quite different ideas of what it meant. There was concern about increased risk, and in some cases they had very limited power to define what methods they used.

Respondents generally felt that they were largely prevented from participating in any meaningful way in demand side management activities by regulatory conditions (although they are involved at the fringes). It was noted by all Government entities that the longer return time frames were an issue and that fundamentally they saw themselves as having a very tight defined scope of work and expertise. Whilst all respondents saw the logic and rapidly increasing cost-effectiveness of many demand side management activities, only the private entities appear willing and able to implement such projects.

Discussion

The creation of a DE market based on equal competition between supply-side and demand-side options at all levels (generation, networks and retail) should help to both optimise DE's contribution to least-cost energy services, and enable the existing electricity industry to adapt their business models and so transition to the 'new normal'. The use of an IRP process should help introduce DE into network planning, and the other measures described above should help introduce DE on a day-to-day basis.

It is important to recognise that for significant levels of DE to be integrated into the electricity network, the impact this has on incumbent utilities needs to be taken into account – especially network operators who operate as a regulated monopoly. This all needs to be considered in the current context of decreasing demand, and the fact that the majority of the charges used to pay for the networks are based on electricity use, rather than demand, and so people who are most responsible for the size of the network are subsidised by those who aren't (PC, 2013). Similarly, people who reduce their electricity use (through whatever means), will reduce their payments for the grid thereby increasing the grid costs faced by others.

Both RIT-D and day-to-day implementation of DE could, if appropriately designed, result in absolute reductions in peak demand and absolute reductions in network costs – by reducing the capacity of the network at times of capital replacement. In addition, as the penetration of distributed storage increases, electricity flows are likely to become less complex, and demand peaks will be reduced, placing further downward pressure on network costs. The increased complexity associated with 'smart grids' will mostly occur behind the meter and so will be paid by the customers who choose to install such options. Allowing network operators to participate directly in the DE market, with appropriate safeguards such as one-way ring fencing, could help them diversify their business models, reducing their dependence on network tariffs, and again placing downward pressure on network costs.

Thus, over the longer term, it is possible that a proportion of the fixed component of network costs could be paid through a fixed daily charge based on a customer's monthly demand peak. In this way, each customer's contribution to network costs would be related more to their impact. The fixed and variable tariffs should be designed to ensure that the various DE options are supported through their ability to reduce both energy use and peaks in demand. This approach is preferable to the current DNSP suggestions of higher fixed charges for all customers, or specifically for PV customers, which would disenfranchise low energy users, disadvantage low income households (by limiting their ability to reduce costs) and also make price signals less cost-reflective.

A fully competitive distributed energy market will need to develop over time, however, the required institutional and organisational changes need to begin now and will need to accommodate both the incumbents and new entrants, on an ongoing basis. It should be noted also that DE technology is developing very rapidly and incumbent electricity sector players are likely to be left with stranded assets if regulatory processes are too slow to adjust. In the longer term, rather than having a separate ‘distributed energy market’ operating alongside the existing NEM, it could be desirable for the NEM itself to operate as a single energy market for centralised and decentralised energy supply and demand.

Contents

1. Introduction

Residential electricity use has been declining each year since 2008/09, driven by a combination of factors including photovoltaics (PV), energy efficiency (EE) and responses to increasing prices (AEMO, 2013). The uptake of PV and EE is likely to continue and will put increasing pressure on utilities' income streams and business models. The responses by utilities and governments to date have essentially attempted to maintain the current business models, however, disruptive technologies such as PV and EE will likely drive the need for more fundamental changes. This report discusses these issues and proposes a regulatory framework that could form the basis of a Distributed Energy market that would optimise DE's contribution to least-cost energy services and enable the existing electricity industry to transition to the 'new normal'.

The report summarises a range of research activities undertaken in Australia and in the US, under an Australian Solar Institute (now ARENA) US-Australia solar research agreement. Although the findings reported here are focussed on the Australian regulatory environment, researchers from both countries have worked together on this project and outcomes will be relevant to both countries. Separate reports and papers will also be published on specific aspects of the work undertaken by the CSIRO and the University of Arizona.

Section 2 describes how and why electricity prices have recently been increasing in Australia, then discusses the possible reasons for the recent decline in electricity use. It then provides some projections for PV uptake, as well as some reasons that uptake may be greater than expected by governments and utilities.

Section 3 summarises work undertaken by the CSIRO, with assistance from the APVA, into consumer attitudes to different types of Distributed Energy, as well as their interest in options to finance their uptake. The types of DE assessed were solar water heaters, grid-connected photovoltaics (PV), grid-connected PV with battery backup, grid-connected battery only, off-grid PV and community PV systems. The financing options were: buy up-front, hire purchase, solar leasing and an ESCO model of ownership. Overall, it was found there is general support by householders to participate in the distributed energy market, particularly through the installation of solar hot water heaters, solar photovoltaic systems connected to the grid for energy generation and with battery backup.

Section 4 outlines the consequences of reduced electricity demand for electricity utilities, with the impact being especially serious for network service providers. Reduced income is the fundamental problem, which could lead to an erosion of credit quality, especially for utilities that fail to adapt with new business models, products and services.

Section 5 summarises the responses by utilities in Australia, then discusses in more detail the responses by governments, especially those aiming to help consumers reduce their electricity costs. They serve to highlight the difficulty faced by governments attempting to both reduce costs for consumers while maintaining revenues for utilities. For both utilities and government, responses have ranged from those that restrict uptake of DE to those that enable increased uptake – with the result that there appears to be no clear nor coordinated direction.

Section 6 explains that when 'disruptive technologies' such as PV (as well as others associated with energy efficiency (EE)), are introduced into a well-established industry, there is a need for fundamental regulatory change. This is needed to not only optimise DEs contribution to least-cost energy services, but to enable the existing electricity industry to adapt their business models and so transition to the ‘new normal’.

Section 7 describes how the fundamental principle of a distributed energy market as defined here is that of equal competition between supply-side and demand-side options at all levels: generation, networks and retail. This can then be subdivided into increasing competition during network planning processes, as well as on a day-to-day basis.

Section 8 proposes Integrated Resource Planning (IRP) as the foundation for introducing more market-based competition between supply and demand side options into networks. IRP considers both supply-side and demand-side options and assesses them against a common set of planning objectives and criteria, where parties other than the network operator can propose both supply-side and demand-side options. It is overseen by an independent (normally government) body, and is subject to regular review. The proposed RIT-D is a basic form of IRP, and while being a good step in the right direction, can be improved.

Section 9 discusses some of the market arrangements required to drive full competition between all supply and demand-side options on a day-to-day basis. These are divided into those related to the operation of the incumbents; those related to the operation of the distributed energy market itself (and therefore new entrants); and those that then stimulate the broader distributed energy market and enhance the interaction and operation of all participants.

Section 10 summarises the interviews undertaken with utilities and regulators that assessed their responses to the proposals outlined in Sections 8 and 9. These interviews highlighted the restrictions placed on both regulators and utilities in dealing with the rapid changes now occurring, and the need for a regulatory environment which more easily allows least-cost options to be undertaken as technology and consumer behaviour changes.

Section 11 then concludes the report, highlighting the issues to be addressed in establishing a distributed energy market and suggesting some courses of action.

2. Electricity prices, demand & PV uptake

In Australia, electricity is mainly produced by coal-fired generators: primarily black coal (46.3% in 2010/11), then brown coal (21.9%), natural gas (19.4%), hydro (6.7%), wind (2.3%), oil (1.2%), bioenergy (0.8%), and PV (0.3%) (BREE, 2012).[2] The residential sector contributes about 30% of electricity demand, with the commercial and industrial sectors making up 23% and 47% respectively (AEMO, 2010). The average household uses about 6,800kWh per year (18.6kWh/day), although this can vary significantly between households, between seasons and between states (ACIL Tasman, 2012).

Residential and commercial electricity prices in Australia have increased significantly between 2008/09 and 2011/12, by on average about 40% nationally (DRET, 2012), with residential prices expected to average 0.325c/kWh in 2012/13, 0.33c/kWh in 2013/14, and 0.34.4c/kWh in 2014/15 – which is about 7% per year (AEMC, 2013a).[3,4] There is a general consensus that electricity prices will continue to increase into the future, although by how much is uncertain (SSCEP, 2012; AEMC, 2012). IPART is now predicting an average price increase of only 1.7% for NSW (with a range of -0.7% to 3.2%) as of July 2013, with a projected increase of 1.8% in July 2014 and a decrease of 6.9% in July 2015 - due partly to linking the carbon price to the EU scheme or removing it altogether (IPART, 2013). In contrast, Qld residential prices will increase by between 7.5% and 22.6% in July 2013, depending on the tariff, with only about a quarter of this increase being due to the previous year's tariff freeze (QCA, 2013a).

Excluding the impact of a carbon price, network expenditure is expected to be the main driver of increased electricity prices from 2010/11 to 2013/14, accounting for 50% of the increase (and 39.6% of the increase in the presence of a carbon price) – see Table 1. More recently the AEMC has estimated that increases in the distribution network component will account for 81% of the national increase in retail residential electricity prices between 2012/13 and 2014/15 (AEMC, 2013a). There is a significant level of concern that this trend in network expenditure will continue and so there is a large amount of discussion going into reducing peaks in demand as well as changing the regulatory framework under which networks operate. These are the focus of the recent AEMC 'Power of Choice' (PoC) Review, which is a major regulatory effort to give consumers more options to reduce their electricity costs (AEMC, 2012).

[2] Since 2010/11, PV installations have increased about three fold and so PV would make up closer to 1.5% of generation in 2012/13.

[3] It is difficult to obtain a reliable estimate of average commercial and industrial electricity tariffs because although regulated tariffs are publicly available, the actual tariffs are generally the subject of negotiation and are commercial in confidence, especially for the large customers – who are responsible for most of the electricity use.

[4] The AEMC is a national, independent body that makes and amends the detailed rules for the National Electricity Market (NEM) and elements of natural gas markets. It also provides strategic and operational advice to the Council of Australian Governments' Ministerial Council on Energy - www.aemc.gov.au.

Table 3. Anticipated Contribution of Components to Retail Electricity Price Increases in Australia to 2013/14[5]
(AEMC, 2011; all values exclude GST)

	Percentage of total price increase attributable to component	
	No carbon (%)	**With carbon (%)**
Transmission	7.6	6.0
Distribution	42.4	33.6
Wholesale energy	24.1	40.2
Retail	13.2	12.1
Green component	12.6	8.1
Total	100	100

In 2013, a partial update to the figures in Table 3 was published (it does not separate out the C price impact), with anticipated price changes between 2011/12 and 2014/15 attributed as follows: transmission 15%, distribution 46%, wholesale energy 25%, retail 13%, contributing to an overall price increase of 21% (AEMC, 2013a).

Electricity prices have recently increased in European countries, although by much less, with the average increase from 2009 to 2011 for the EU-27 being 12.2% (households) and 8.7% (industry) (Eurostat, 2012). Average electricity prices in the United States over the same period have increased very little, with residential increasing by 2.7% and commercial by 1.9% (EIA, 2012). The increase in electricity costs in Australia has become a political issue and resulted in a large number of reports and reviews from government (e.g. SSCEP, 2012) as well as industry and community representative bodies (e.g. OG, 2012).

Electricity use in Australia has decreased in absolute terms every year since 2008/09, with a total decrease of about 8,300GWh (5.5%) by 2012/13 (AEMO, 2013). After dealing only with load growth since the introduction of the National Electricity Market (NEM), the Australian Energy Market Operator (AEMO)[6] has had some difficulty anticipating these reductions,[7] with, for example, the actual 2011/12 demand being 5.7% less than the forecast for that period made in August 2011 – see Figure 10. Most recently, AEMO has reduced the 2013/14 NEM demand forecast it made in 2012, by another 2.4% – see Figure 11. While the most recent forecasts are now lower than earlier ones, and allow for some uncertainty through low, medium and high growth scenarios, electricity use is still assumed to trend upwards in the near future, albeit at a slightly lower rate (AEMO, 2013).

However, and of most relevance here, it is important to note the continued decline in residential and commercial electricity use per capita, with national demand increases in these sectors dependent on the accuracy of population growth projections (AEMO, 2013).

[5] Note that the Ministerial Council on Energy agreed on 7th December 2012 to implement a number of changes to Network regulations which are expected to reduce these projected increases. Also, falling demand, including peak demand, is already resulting in the deferral of some planned and approved network expansion.

[6] AEMO is a national, independent body and is the National Energy Market Operator and planner. It both maintains critical services and sets new directions in energy sector planning.

[7] Note that this difficulty with forecasting demand has also occurred for network operators and state governments (AEMC, 2013b).

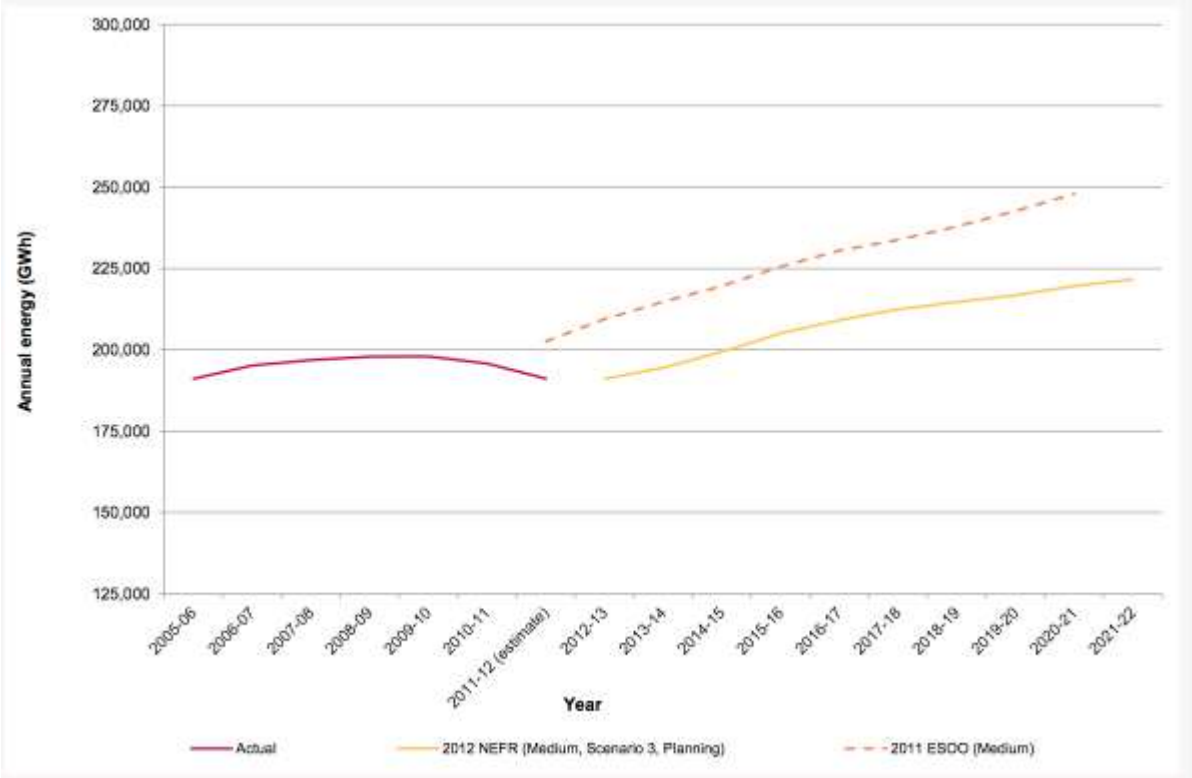


Figure 10. Comparison of the 2012 NEFR and 2011 ESOO annual energy forecasts for the NEM (AEMO, 2012a)

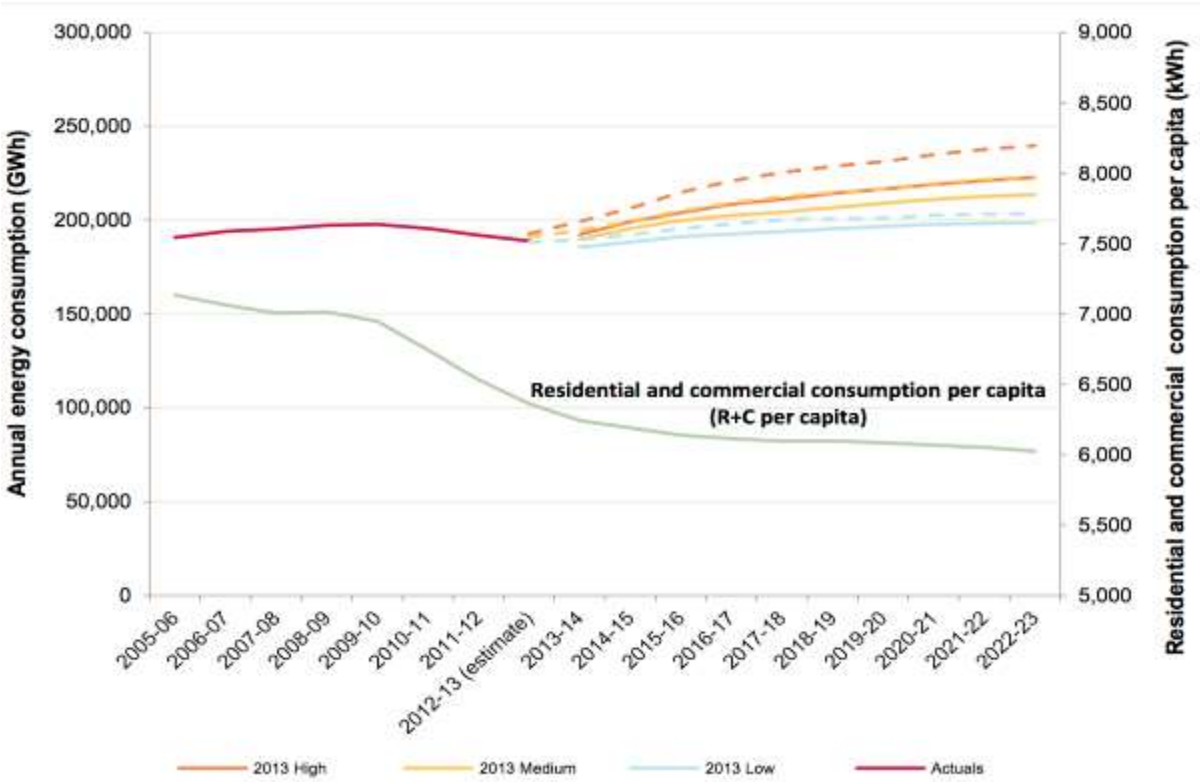


Figure 11. Comparison of annual energy forecasts made in 2012 and 2013 for the NEM under three growth scenarios (AEMO, 2013)

AEMO has attributed the decline in electricity use to a range of factors, including lower GDP, reduced manufacturing, the uptake of PV, solar water heaters (SWH), and energy efficient technologies, as well as increasing electricity prices.[8] Figure 12 shows AEMO's projection for the different components of electricity demand out to 2022-23. The growth in residential and commercial demand is driven by assumed population growth (note the y-axis starts at 140,000, and so the increase is only about 10%). The impact on utilities will depend on the net effect of reduced electricity use per capita and increased population growth.

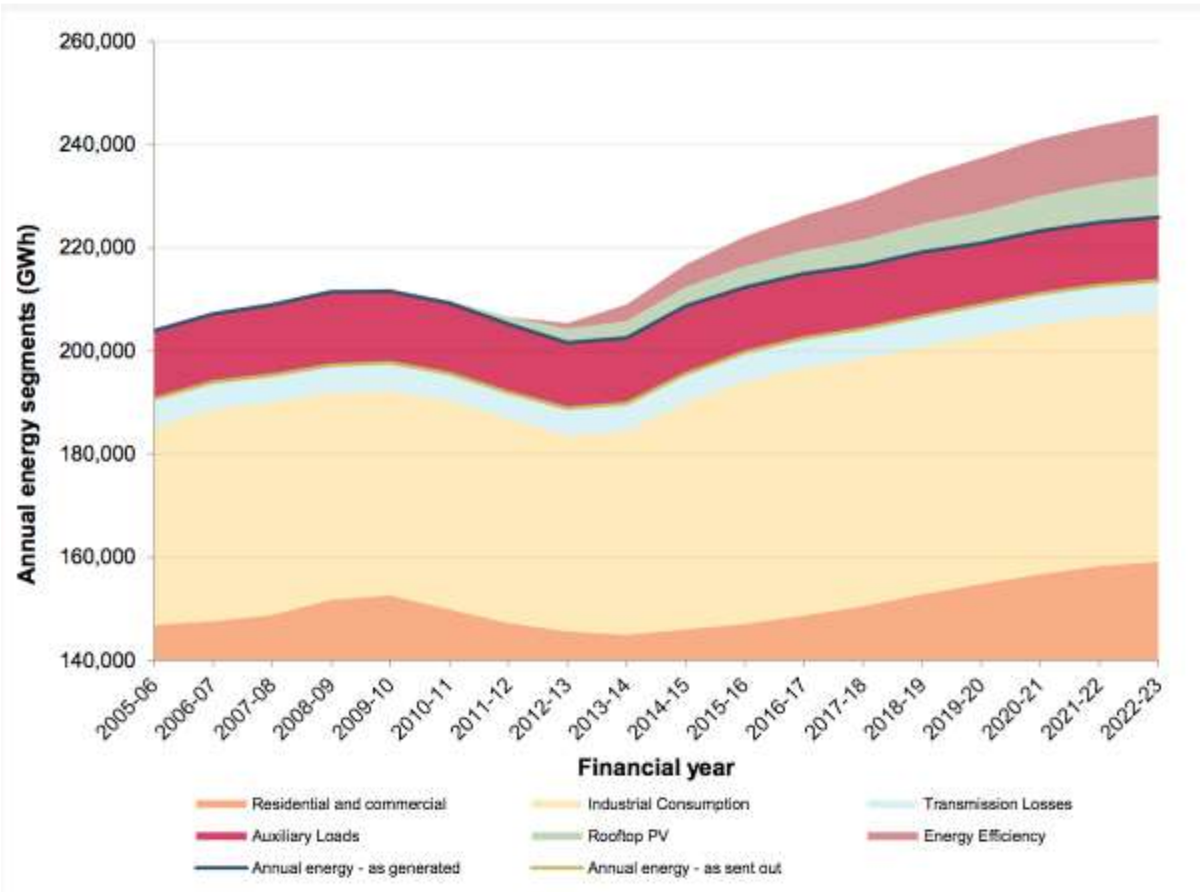


Figure 12 Components of the decline in NSW electricity demand from 2008 to 2012 (AEMO, 2013)

For NSW, Intelligent Energy Systems attributed the decline as shown in Figure 13. Although in 2011, distributed generation (both PV and larger embedded generators) and SWHs accounted for about 60% of the decline, in 2012 their relative contribution decreased because of the decline attributed to the closure of the Kurri Kurri aluminium smelter and Bluescope Steel mothballing its No. 6 blast furnace, as well as what are thought to be general energy efficiency measures and the impacts of higher electricity prices (IES, 2013).[9]

[8] Due to lack of reliable data it is difficult to attribute the decline to particular factors. However, about 1.38GW more PV was installed in 2011/12 than in 2008/09 (APVA, 2012), which would account for about 1,500GWh, or 20% of the decrease.

[9] Compared to 2008, the NSW decline in 2012 is thought to be due to: 0.4% weather, 10% PV, 7% SWHs, 7% larger embedded generation, 26% closure of Kurri Kurri, 14.5% closure of Port Kembla steel furnace, and 37% due to general reductions in demand due to EE measures and price impacts.

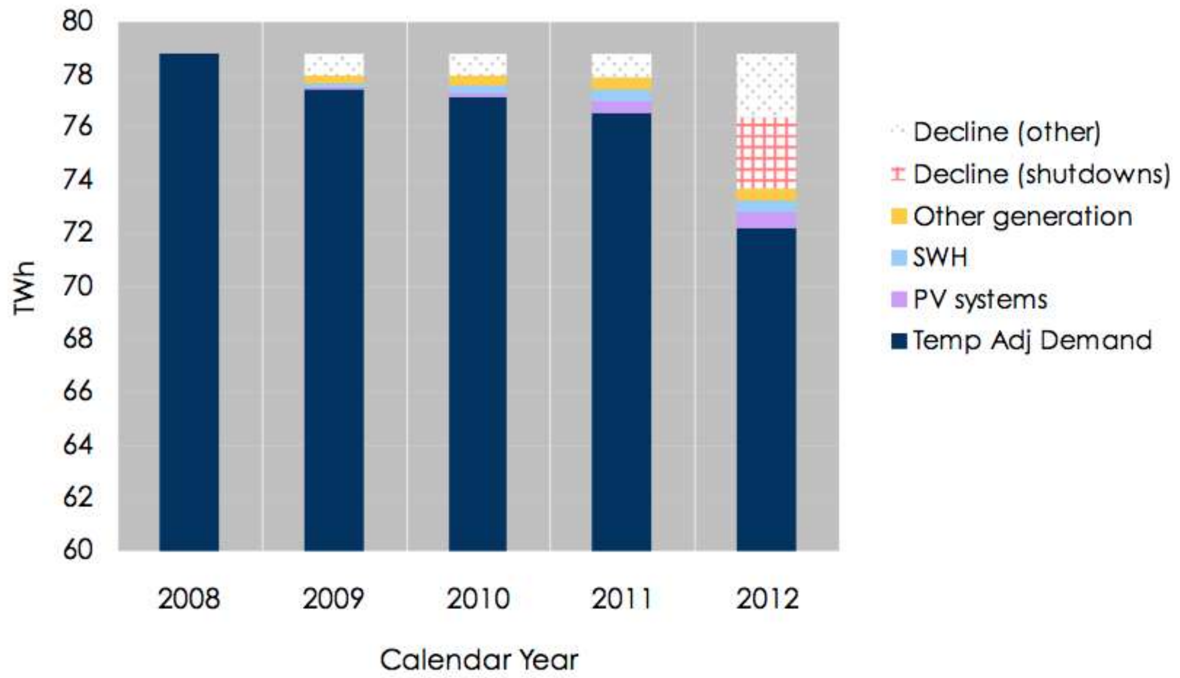


Figure 13 Components of the decline in NSW electricity demand from 2008 to 2012 (IES, 2013)

Figure 14 shows the change in average residential demand in the Energex area of Qld from May 2009 to Jan 2013. It shows that PV-owners have significantly lower average demand that non-PV-owners, and there has been a steady decline overall (RE, 2013). As more customers take up PV it is clear that total sales will decrease further.

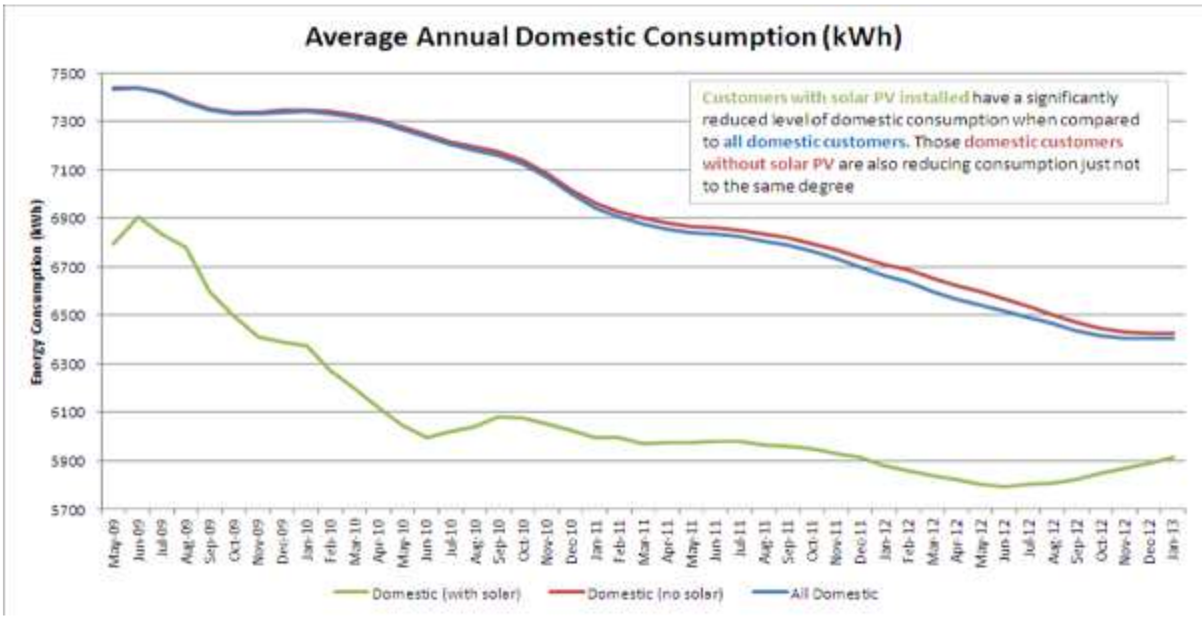


Figure 14 Energex residential demand with and without PV (RE, 2013)

While GDP and manufacturing may increase to previous levels (although it is unlikely the Kurri Kurri aluminium smelter will be reopened), for electricity growth to return to trend would require electricity prices to decline (in real terms), along with a reduced rate of uptake of PV, SWHs and EE technologies – none of which appear likely. In fact, PV and energy efficiency markets are broadening, with PV now moving strongly into the commercial sector, where system sizes are in the 10-100kW range. By May 2013, well over 100 commercial systems had been installed.[10]

AEMO has recently undertaken projections of PV uptake in Australia out to 2031 - see Figure 15. The moderate scenario resulted in 6,350 GWh by 2020 and 15,400 GWh by 2031 (AEMO, 2012b). These figures were revised slightly higher in a subsequent report, to 7,558 GWh by 2020/21, meaning that PV's contribution to total electricity generation would increase from 0.9% in 2011/12 to 3.4% in 2021/22.

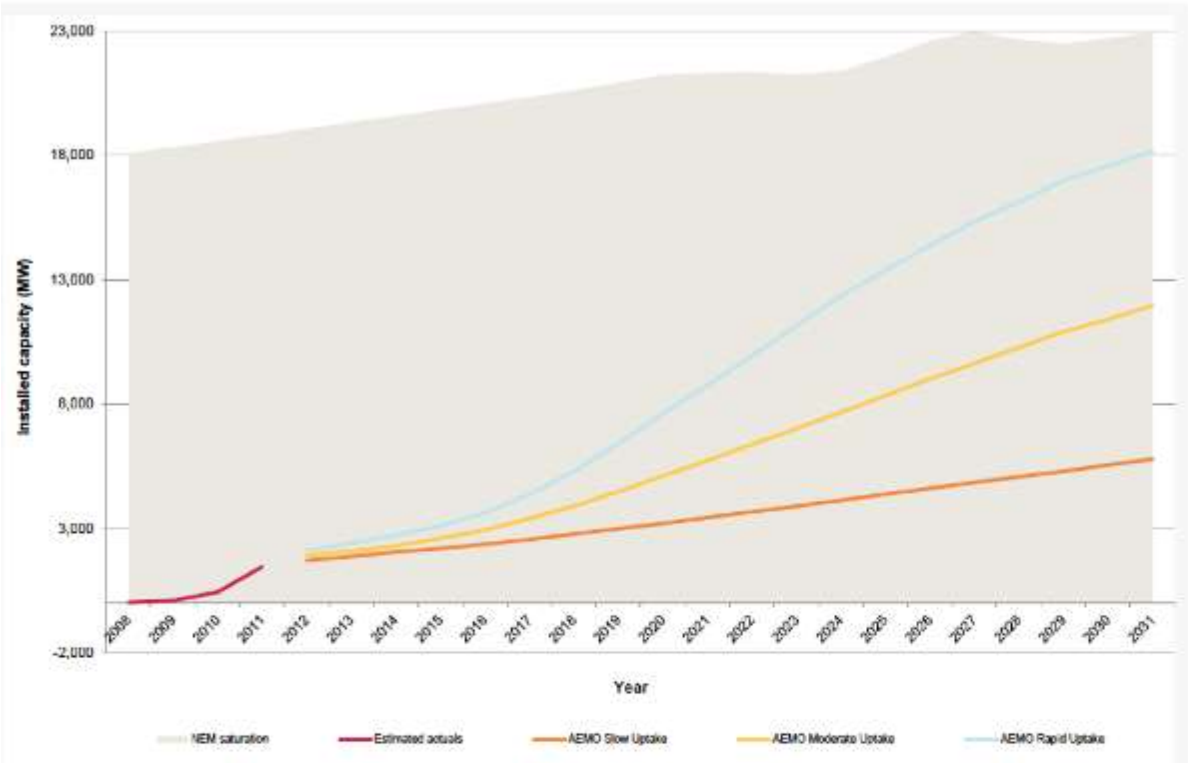


Figure 15. Projections of PV uptake in Australia (AEMO, 2012b)

The CSIRO recently published some analysis that included the uptake of DG and PV in particular under various scenarios. Figure 16 shows the total generation mix and Figure 17 shows the DG by technology type under the CPRS-5 scenario.[11] It can be seen that by around 2020, DG makes up about 10% of the generation mix, with PV making up a relatively small proportion of this. However, by 2030 these values have increased to over 20% and over 35%, both steadily increasing thereafter (Lilley et al., 2013). PV produces about 24,000 GWh in 2030, which equates to at least 18,000 MW.

[10] From http://sunwiz.com.au/index.php/large-system-list.html

[11] The other scenario illustrated in Lilley et al. (2013) showed slightly less DG but a similar amount of PV and more centralised renewables.

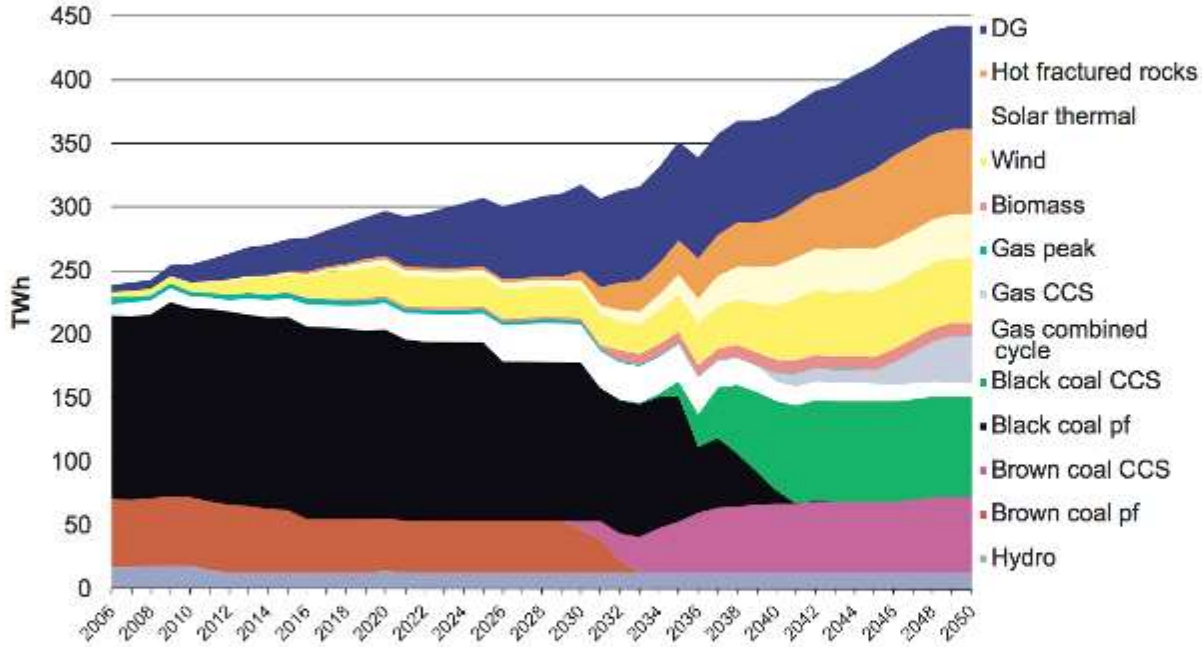


Figure 16. National Electricity Generation Under CPRS-5, 2006-2050 (Lilley et al., 2013)

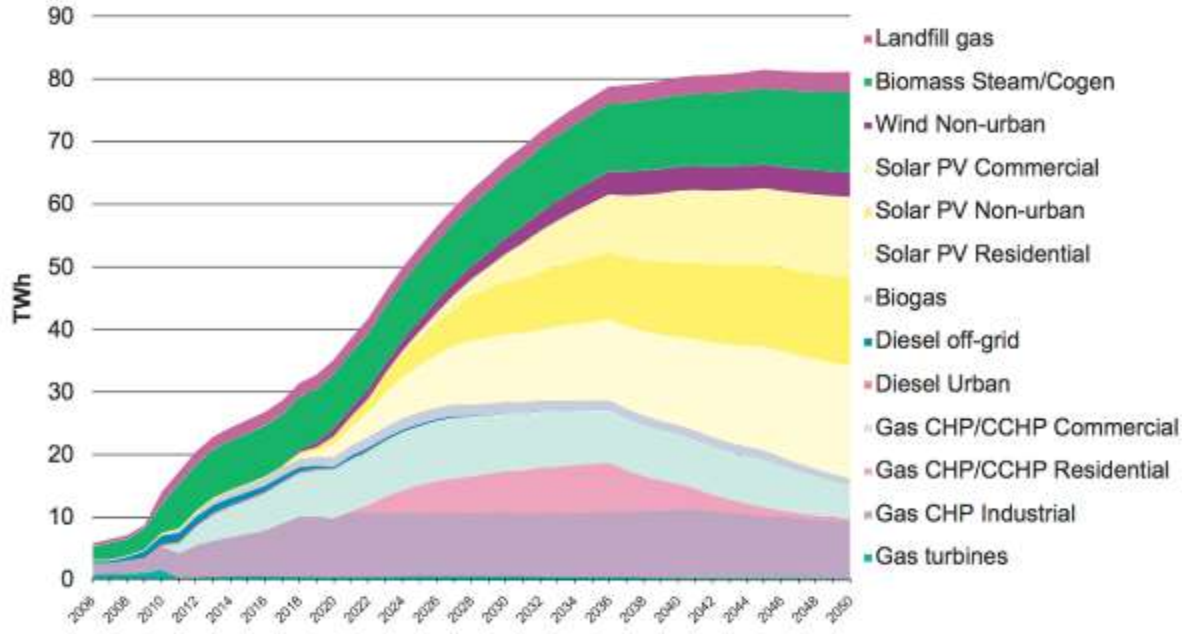


Figure 17. Distributed Generation by Technology Under CPRS-5, 2006-2050 (Lilley et al., 2013)

While there is always significant uncertainty with such projections, it is possible that PV uptake could be higher than even AEMO's Rapid Uptake scenario. Increased rates of uptake could be driven by (i) PV prices declining faster than anticipated, (ii) novel business models such as solar leasing, crowd sourcing and community PV, and (iii) battery technology prices declining and enabling higher levels of penetration per household (Schleicher-Tappeser, 2013; Eadie and Elliott, 2013).[12] Figure 18 shows a range of other projections for PV uptake in Australia out to 2020, all of which are higher than the AEMO Moderate Uptake forecast (Eadie and Elliott, 2013). California's Public Utilities Commission has released a proposal that sets out annual targets, for the three utilities Pacific Gas & Electric, Southern California Edison and San Diego Gas & Electric, that requires the deployment of storage for transmission, distribution and 'customer-facing' sectors. Such requirements highlight the fact that not only is storage coming of age, but that it is seen as desirable by some state regulators (PUCSC, 2013).

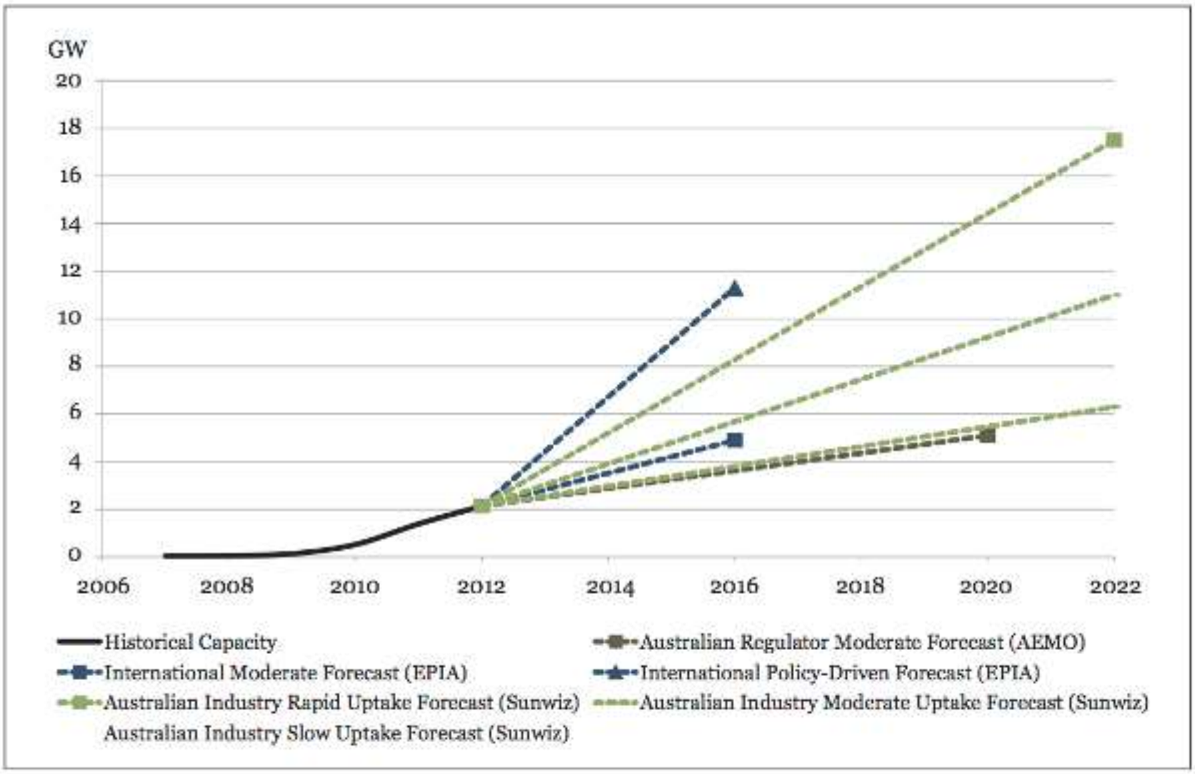


Figure 18. Range of projections of PV uptake in Australia (Eadie and Elliott, 2013)

There is also increasing focus on EE, not only on the residential sector through state-based schemes, but on commercial and industrial sectors as well. A recent report on industrial EE indicated that, under current policy settings, companies that account for half of Australia's energy use are expected to implement EE actions that could reduce their energy use by 4.8% - mostly through actions with a payback time of less than 2 years. Both increasing energy prices and targeted government support would result in greater reductions in energy use (CWA, 2013).

While it is impossible to accurately predict the actual level of electricity use in the future, should demand continue to decrease or even increase at a significantly lower rate than in the past, this would have important consequences for the electricity industry, especially network operators, who face increasing costs.

[12] SMA Solar Technology has recently announced that it will be offering a PV inverter (Sunny Boy Smart Energy) with an integrated a lithium ion battery, that would provide an average household 3 hrs storage. Such innovations will almost certainly accelerate the uptake of storage technologies, and hence PV systems.

3. Consumer Interest in Distributed Energy Options

This section summarises work undertaken by the Commonwealth Scientific and Industrial Research Organisation (CSIRO), with assistance from the APVA. It also includes some interpretation of the results by the authors of this report. The CSIRO firstly conducted focus groups (FGs) that investigated the range of stakeholder opinions and likely preferences in relation to opportunities for participating in distributed energy and demand side response activities (Ashworth et al., 2012). The analysis of these FGs was then used to inform a national survey which was delivered across Australia in early 2013 (Romanach et al., 2013). The complete reports for the FGs and surveys can be found in Appendix A and Appendix B respectively.

3.1. Focus Groups

Six FGs were conducted with a total of 61 members of the Australian public in Brisbane, Melbourne and Sydney in October, 2012. An expert from the APVA was enlisted to present peer reviewed DE options to the participants in the FGs – see Table 4. Participants were also presented with four different payment options: Up front payment, hire purchase, solar leasing and energy service companies (ESCOs).

Table 4 Distributed Energy Options presented to the Focus Groups

Solar PV technology options		
Option	Solar technology	Abbreviation
1	Energy efficiency and solar hot water systems	SHW
2	Grid connected solar PV	SPV
3	Grid connected solar PV with battery	SPVB
4	Battery alone	BA
5	Community PV	CPV
6	Off grid PV systems with battery and generator	OG

Through all of the focus groups, cost of electricity and the opportunity to reduce energy bills was a prime motivator for participants. Many had undertaken a number of energy conservation actions to try and reduce their bills and the most frequently cited were turning off lights, standby switches and appliances when not in use, undertaken by 75% of participants; followed by purchasing and installing additional energy efficient measures such as ceiling fans, heat pump hot water, solar lights and solar hot water which was undertaken by 46% of participants. The most popular distributed energy model was grid-connected solar PV which 11 participants already owned.

When it came to purchase options, the majority of participants preferred to buy upfront if at all possible. The main reason given was that buying up front would provide participants with the required energy independence that most sought, particularly in relation to being self sufficient and supplying their own electricity needs. Incentives were also mentioned as being important, as well as the likely return on investment based on the original cost of solar and how much it might contribute to reducing electricity bills.

There is significantly more information in the full FG report (Appendix A), however, the main aim of the FGs was to inform the survey questions, and, because the survey results are more reliable from a statistical point of view, they are used in preference to outcomes of the FGs and so are discussed in more detail below.

One point worth noting however, is that the FGs served as a useful means to educate (a small section of) the public. Figure 19 shows the mean ratings for subjective knowledge before and after the FG. Results from the paired sample t-tests show that participants' knowledge significantly increased as a result of the information provided in the FG ($p<0.001$). Following the presentation, participants agreed or strongly agreed that they could easily explain solar energy and all six associated technologies.

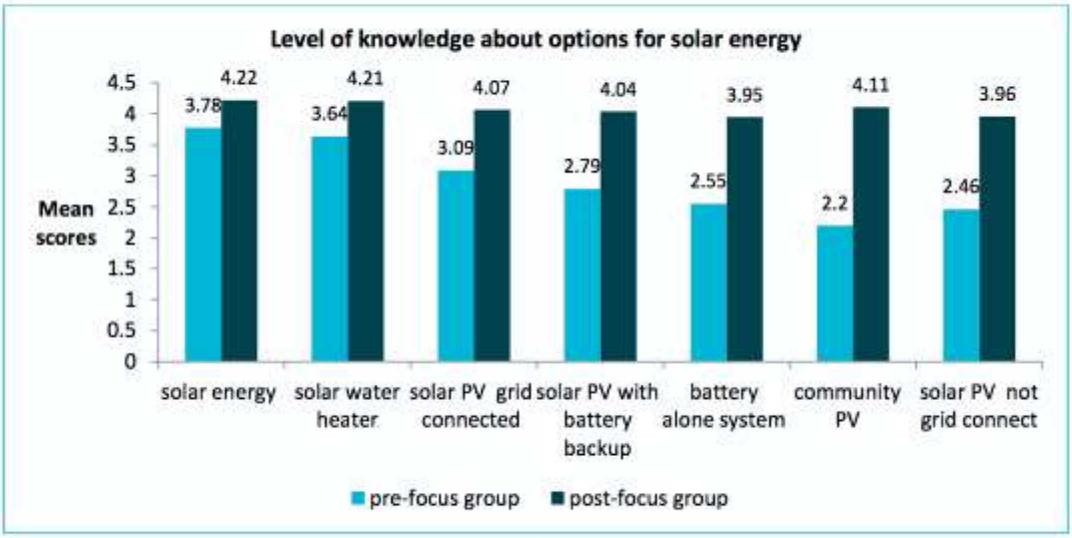


Figure 19 FG participants' ability to explain to a friend DE options before and after the information provision

3.2. Surveys

A total of 2,463 individuals participated in the internet survey. They were reasonably representative of the Australian population in terms of gender and age, with females slightly over represented, as were the 65-69 age range, while the over 75 year olds were underrepresented. Respondents were from all over Australia, with their geographical distribution corresponding to the distribution of the total population. Other characteristics of the respondents can be found in the full report (Appendix B). The technology and payment options were the same as those used for the FGs.

3.2.1. Technology preferences

A total of 18.3% of respondents owned PV systems and 11.9% owned SWHs. Figure 20 shows the composite score for acceptance (whether it sounds like a good idea, has the support of family and peers, and is feasible and suitable to have at home) of respondents who didn't already own these technologies. It can be seen that householders, on average, think that all the options 'sound like a good idea'. Note the acceptance score or support towards distributed solar energy is defined as scores significantly above the neutral scale on a 5-point Likert scale, i.e. 3.5 or higher (where 1 represents 'strongly disagree' and 5 represents 'strongly agree'). When asked if they would consider installing one of the options, both SWHs and grid-connected PV rated positively, as did grid-connected PV with batteries. However, respondents were on average neutral to off-grid PV, battery-alone and community PV systems.

Support for distributed energy technologies does not appear to differ significantly across age, gender or income groups. However, survey results indicate that those respondents living in houses exhibit higher levels of support for SWHs, grid-connected PV and grid-connected PV with batteries.

Figure 21 shows the composite score for acceptance (they are happy with the system, they would consider further investment, and has the support of family and peers) of respondents who do already own these technologies. It can be seen that, on average, they clearly support all these statements.

For respondents who already owned SWHs and/or PV systems, saving money on their power bill was clearly the main reason for purchase – see Figure 22. The reduction of electricity costs was also given as the most favourable attribute of all the DE options for those who had not yet purchased them.

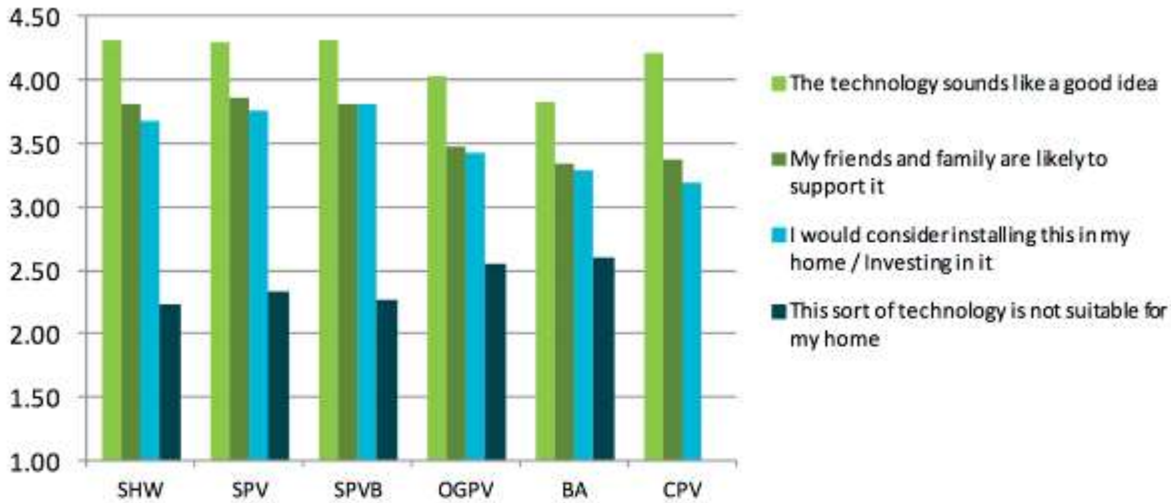


Figure 20 Acceptance of DE technologies (respondents not already owning these technologies)

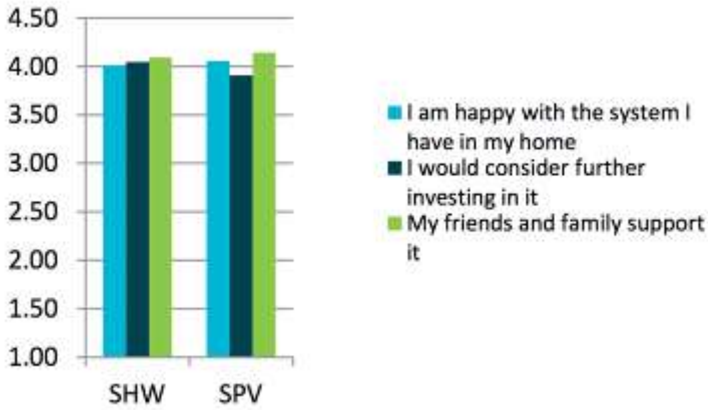


Figure 21 Acceptance of DE technologies (respondents not already owning these technologies)

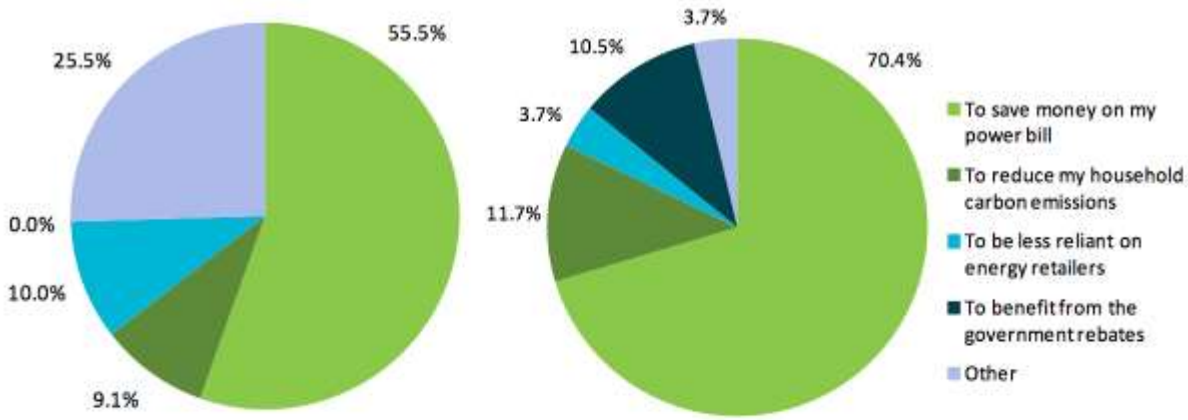


Figure 22 Reason for having purchased SWHs (left) and/or PV systems (right)

3.2.2. Payment preferences

Figure 23 shows the respondents' interest in different payment options for the DE technologies. There is a clear preference for paying up front, rather than using finance, leasing or through an ESCO. The ESCO option had both the highest number of respondents say they were least interested as well as the second highest number of respondents say they were most interested.

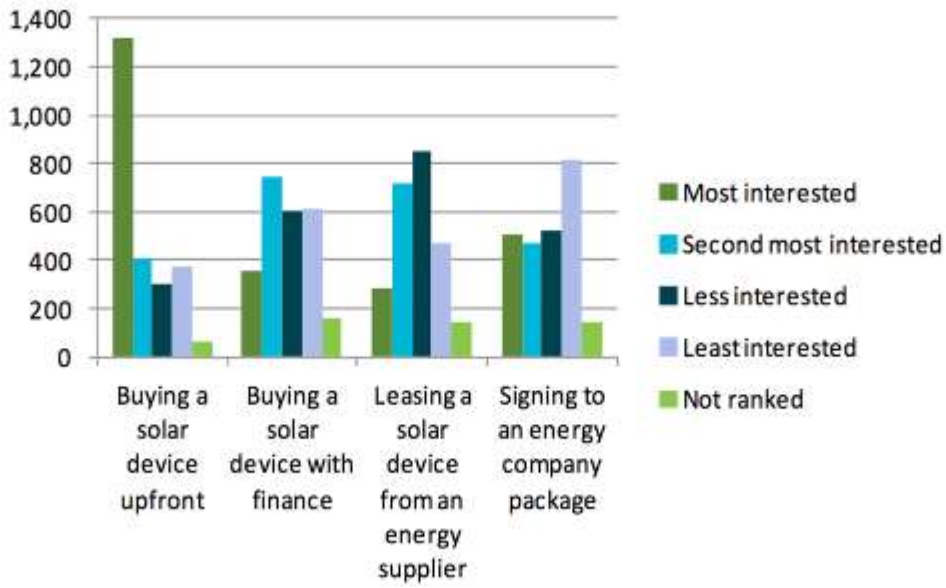


Figure 23 Ranking of finance options to install or replace one of the technology options

3.2.3. Summary

As for the FGs, the original CSIRO survey report (Appendix B) includes significantly more information than presented here. The material included in this Section is only that most directly relevant to this report.

It is clear that respondents who have already installed grid-connected PV and SWHs are very happy with their purchase, and would consider installing more. It is also clear that, on average, the remainder of respondents would consider installing both grid-connected PV and SWHs, and most interestingly, grid-connected PV with batteries.

With respondents' being more interested in grid-connected PV with batteries than in batteries alone, it is likely that PV will drive the uptake of batteries – with the coming release onto the market of the SMA Sunny Boy Smart Energy PV inverter being a good example. This will in turn enable the installation of larger PV systems and so further reduce electricity demand.

Note that all these scores are for average values across all respondents, including those who don't own their own home or for some other reason might find it difficult to use these technologies, and so don't clearly show the proportion of individuals who might be strongly interested in a particular option.

Cost savings are by far the primary driver for installation of PV and SWHs, and with the ongoing decline in installed costs of both PV and batteries, combined with the likely increases in grid electricity costs, the strength of this driver is likely to increase.

3.3. University of Arizona Project

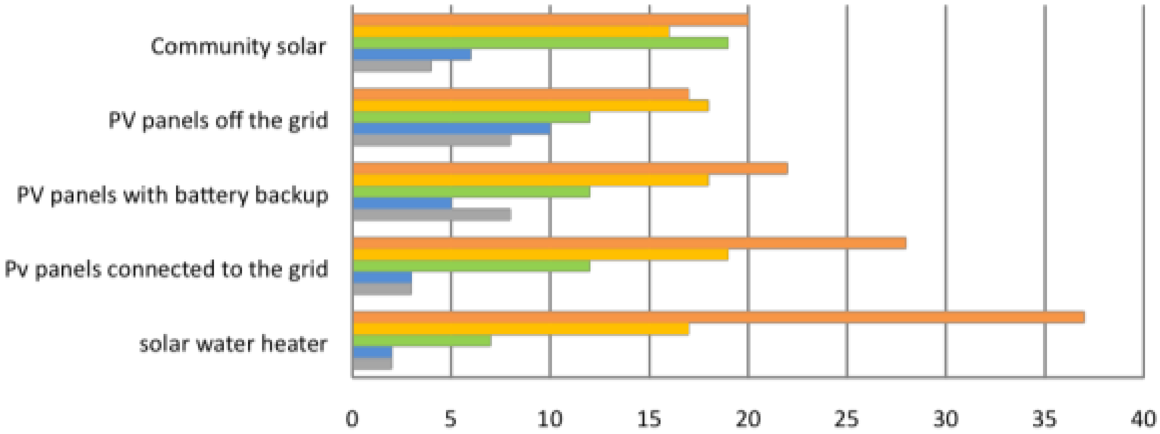
The University of Arizona is applying the approach used here to assess individuals' interest in different types of DE technologies and options to pay for them. At the time of writing, they had conducted four focus groups in Mexico, and the following summarises the key outcomes that are most relevant here (Barquero and Barnhart, 2013).

3.3.1. Mexican Focus Groups

Four FGs were conducted with a total of 65 people from the Mexican cities of Navolato, Culiacan, Mexico City and Guadalajara in March, 2013. Participants were presented with the same technology options as the Australian FGs, with the exception that the 'battery alone' option was not included. They were presented with three purchase options: Up front payment, hire purchase, solar leasing.

Prior to the FG, participants were asked whether they would consider installing any of the technology options. Their responses are shown in Figure 24, and it can be seen that the most preferred technology was solar water heaters, then grid-connected PV followed by grid-connected PV with battery backup. The least preferred options were community solar then off-grid PV.

These outcomes are remarkably consistent with those of the Australian survey, with the only difference being that, in Australia, grid-connected PV (with ot without batteries) was ranked essentially as highly as SWHs. The Mexican relative preference for SWHs compared to PV most likely reflects their greater familiarity with that technology.



	solar water heater	Pv panels connected to the grid	PV panels with battery backup	PV panels off the grid	Community solar
Strongly Agree	37	28	22	17	20
Agree	17	19	18	18	16
Neither agree or disagree	7	12	12	12	19
Disagree	2	3	5	10	6
Strongly disagree	2	3	8	8	4

Figure 24 Interest in installing a technology option (pre-FG)

Following the FGs the participants were again asked whether they would consider installing each technology option - Figure 25. The only changes to the pre-FG results were that participants' second preference was grid-connected PV with battery backup (rather than grid-connected PV), and community solar was now ranked lower than off-grid PV. It was thought that the most likely reason for the change in preference ranking was simply due to participants being more familiar with the technologies following the FGs. In this case, the main difference to the Australian results was, again, the preference for SWHs, grid-connected PV with batteries being more preferred than grid-connected PV, and community solar being the least preferred.

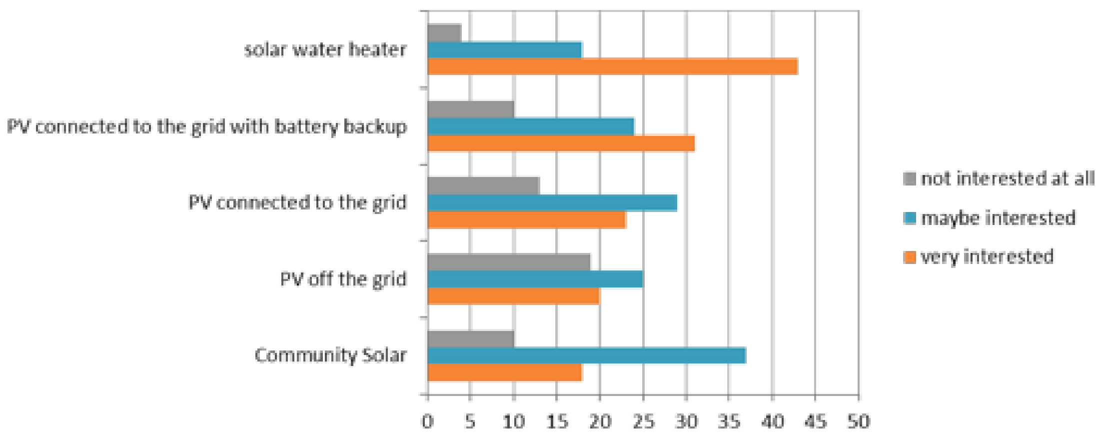


Figure 9. Participants interest to install solar technologies

Figure 25 Interest in installing a technology option (post-FG)

Participants' preferences for the three purchase options are shown in Figure 26. There was a clear preference for financing through hire purchase, then buying upfront then solar leasing. This is in contrast to the Australian results, where buying upfront was clearly the preferred option. As occurred in the CSIRO FGs, the participants' subjective knowledge of the different technology options significantly increased as a result of the FGs (P<0.05).

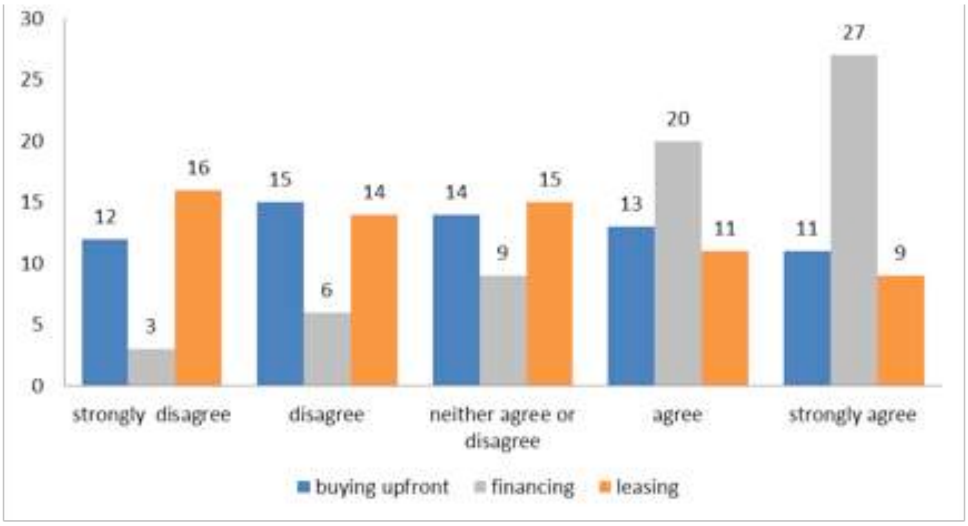


Figure 16. Purchasing preferences

Figure 26 Ranking of finance options to install or replace one of the technology options

4. Consequences for Utilities

According to the recent Commonwealth Energy White Paper, the lower than expected electricity use discussed above has caused problems for the incumbent electricity industry. Generators operating in the wholesale market have suffered not only from reduced sales but also from reduced wholesale market prices resulting from reduced demand and increased large-scale renewable energy generation (DRET, 2012).[13] According to the Energy White Paper, 30% of the revenue from the wholesale market comes from just 30 hours of critical peaks a year. This means that while wholesale generators' operating costs may be covered (because they won't bid into the market at less than their short run marginal cost), they may have difficulty paying off their capital costs (for which they need to sell electricity at their long run marginal cost).

Network operators are regulated monopolies and receive the majority of their revenue from tariffs linked to electricity use.[14] Ongoing decreases in electricity consumption, especially per customer, therefore put increasing pressure on network operator revenue. The need to maintain revenue is compounded by the fact that only about half the current network expenditure is used to meet load growth and increases in peak demand, with the remainder for the replacement of aging sections of existing networks (Ernst & Young, 2011).[15] This means that even if peak demand decreases, a significant amount of network expenditure will be required regardless, if the current size of the network is to be maintained.

The current retail market depends on kWh sales and a daily connection charge.[16] While these tariffs vary between retailers, an average residential customer would provide the retailer with 85% to 90% of their revenue through the usage charge.[17] Although reduced sales result in reduced profit, retailers have low capital costs, and can scale down their operations.

Thus, while decreased electricity use could result in decreased costs for consumers from the wholesale and retail sectors (to the extent that these reductions are passed through), this is not the case for the networks, because under the current regulatory arrangements, network investments must be paid for, and network operators are allowed to apply for tariff adjustments to ensure that they are.[18] The ability of network operators to pass through all network costs reduces their incentive

[13] In Australia, the wholesale market operates on a competitive basis, which essentially means that the least-cost generation options are dispatched at any one time. Renewable energy generators can bid into the market at, or close to, zero, which lowers the dispatch price. Even when bidding in at zero they maintain a revenue stream through renewable energy certificates.

[14] For example, for the New South Wales Transmission Network Service Provider Transgrid, charges related to usage make up about 80% of total revenue projected for the 2009/10 to 2014/15 period (Transgrid, 2010).

[15] In 2010/11, 44.7% of Distributed Network Service Providers (DNSP) expenditure was to meet load growth and increases in peak demand, while 52.5% of TNSP expenditure was for this reason (Ernst & Young, 2011).

[16] In the retail market, electricity retailers supply customers on either regulated tariffs or under competitive market arrangements. Prices of regulated tariffs may be set by the retailer (and approved by the jurisdictional regulator), or where retail price regulation is still in place, would be set by the jurisdictional regulator. Regulated retail tariffs are offered in all jurisdictions except for Victoria, and in all cases market-based tariffs are also available (AEMC, 2011).

[17] Based on 7,000kWh per year, an AUD 27.53c/kWh usage charge and 69c/day connection charge – from http://www.originenergy.com.au/3986/NSW-pricing-tariffs.

[18] Being natural monopolies, networks are regulated, and the exact form of this regulation differs between transmission and distribution networks as well as between different jurisdictions (which in Australia refers to the different states and territories).

for demand management or other lower cost alternatives to network augmentation, and so is considered to contribute to the recent high level of network expenditure (SSCEP, 2012).

Utilities being negatively affected by decreasing electricity use is not a new problem and is not restricted to Australia. For example, it is also occurring in the US (York and Kushler, 2011; Kind, 2013) and throughout Europe (Schleicher-Tappeser, 2013). A recent report commissioned by the Edison Electric Institute (EEI report), which describes itself as 'The Association of Shareholder-Owned Electric Companies', when referring to 'disruptive challenges', stated that (Kind, 2013, p1):

> *"…falling costs of distributed generation and other distributed energy resources (DER); an enhanced focus on development of new DER technologies; increasing customer, regulatory, and political interest in demand-side management technologies (DSM); government programs to incentivize selected technologies; the declining price of natural gas; slowing economic growth trends; and rising electricity prices in certain areas of the country …… are potential "game changers" to the U.S. electric utility industry, and are likely to dramatically impact customers, employees, investors, and the availability of capital to fund future investment ….*
>
> *….The financial risks created by disruptive challenges include declining utility revenues, increasing costs, and lower profitability potential, particularly over the long-term….*
>
> *…. Left unaddressed, these financial pressures could have a major impact on realized equity returns, required investor returns, and credit quality….."*

The EEI report goes on to refer to a 'vicious cycle from disruptive forces' where increases in usage charges driven by the charges to be increased again, which further reduces electricity use – see Figure 27. In Australia this has been termed an 'energy market death spiral' (Simshauser and Nelson, 2012).

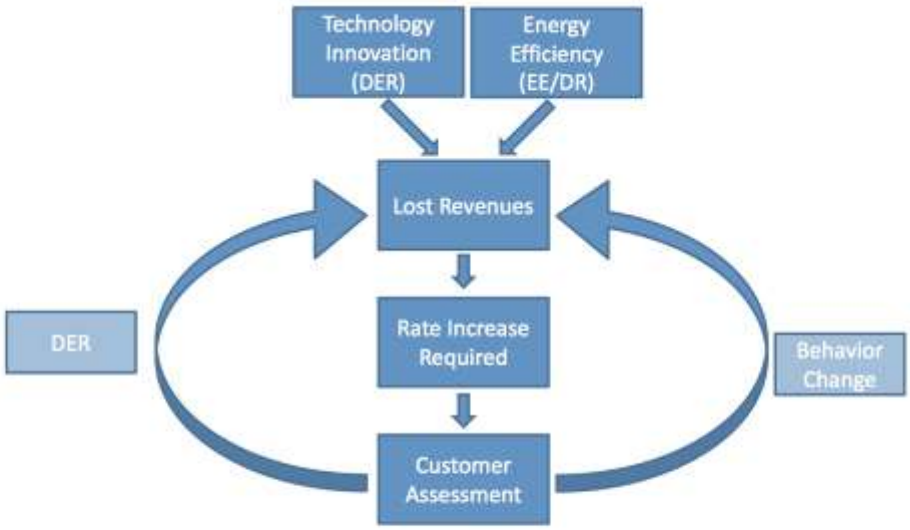


Figure 27. Vicious Cycle from Disruptive Forces (Kind, 2013)

According to the EEI report, since the 1970s, credit quality has been reduced by a combination of supply-side cost pressures, declining economic and customer growth trends, inflation in cost-of-service provision, and an evolving industry and regulatory model – see Figure 28. The report warns that the above 'disruptive forces' mean that further erosion of credit quality is a significant risk for utilities.

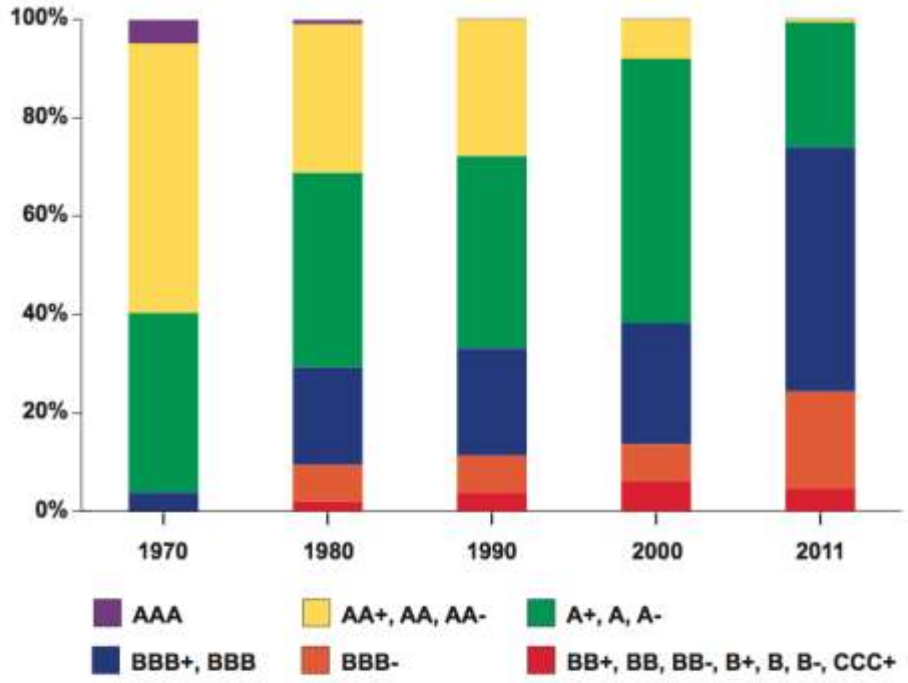


Figure 28. Decline in Utility Credit Quality (Kind, 2013)

The report also has an interesting extension to the fixed line telephony analogy to the electricity industry. They firstly state (Kind, 2013, p15):

> *"There are important lessons to be learned from the history of the telephone industry. First, at the onset of the restructuring of the Bell System, there was no vision that the changes to come would be so radical in terms of the services to be provided and the technologies to be deployed. Second, the telephone players acted boldly to consolidate to gain scale and then take action to utilize their market position to expand into new services on a national scale. Finally, and most important, if telephone providers had not pursued new technologies and the transformation of their business model, they would not have been able to survive as viable businesses today."*

It then goes on to point out that the so-called 'disruptive technologies' are not immune from this effect, citing the displacement of the Blackberry by the iPhone as an example of the ongoing evolution that would likely apply to the DE industry. The report also states that a significant difference between the electricity and telephony industries is that although telephony services can now be provided completely independently of the original landlines, this is not the case for most electricity users who will still be connected to the grid. However, it is also clear that, even if customers stay connected to the grid, DE technologies will have a significant impact on utility revenue, and those that fail to adapt with new business models, products and services are unlikely to survive.

5. Responses by Utilities and Governments

To date, there have been a variety of responses by government and utilities to reduced electricity use and increasing uptake of DE. The responses by utilities essentially focus on maintaining the current types of revenue streams and business models. Government responses have been more varied, ranging from those that attempt to directly reduce network costs for consumers and enable limited uptake of DE, to those that actively oppose DG options such as PV. They generally involve relatively minor changes to the regulatory environment.[19]

5.1. Responses by utilities

The responses by utilities can be subdivided into the following:

6. Implementation of TOU tariffs: This is spearheaded by AGL and its stated intention is to make tariffs more cost-reflective – so that retail prices are better aligned with the network costs of electricity demand (AGL, 2013). As discussed below, this reflects one of the recommendations of the Final Report of the Power of Choice (PoC) Review by the Australian Energy Market Commission (AEMC). Both AGL and the PoC Review also emphasise the need to protect vulnerable customers.
7. Higher demand charges: This is occurring throughout Australia in the commercial sector. According a recent report by Big Switch Projects, based on a survey of 66 large commercial customers, between June and July 2012 usage charges increased by an average of 18.6% (including the impact of the carbon price), whereas peak demand charges increased by an average of 30% (BSP, 2012).
8. Higher fixed daily charges: This is occurring throughout Australia, and the degree to which it is being used to reduce the rate of increase of usage charges is unclear. For example, the fixed charge for residential Tariff 11 in Qld will increase by 91.9% in July 2013, with only about a quarter of this increase being due to the previous year's tariff freeze (QCA, 2013a). The Energy Supply Association of Australia (ESAA) has recently stated that owners of PV systems are not paying their fair share of network costs and so have proposed they pay a higher fixed charge than other electricity users (ESAA, 2013). As discussed below, this claim has also been made by the Queensland Competition Authority (QCA, 2013b). E.ON, a German utility, recently said customers may end up not paying by the kWh but instead may pay in bundles as they currently do for phone plans ie. in flat fees per month for defined services, which could include higher connection fees (Tweed, 2013).
9. Limited participation by retailers in providing distributed energy: A number of retailers are selling PV (eg. Origin, AGL, EnergyAustralia) and some are promoting the use of home energy portals that provide information to end users that help them to manage their energy use (eg. Origin).
10. Low payments for PV export: According to Eadie and Elliott (2013), Origin, AGL and EnergyAustralia supply 80% of small retail electricity customers and control close to 30% of mainland National Electricity Market generation capacity. Such retailers pay relatively low prices for PV electricity that is exported to the grid – with rates at the lower end of, or below, the benchmark range recommended by governments.

[19] A recent exception to this is the decision by the AER to regulate NSW and ACT DNSPs under a revenue cap for the provision of standard control services. This is discussed in Section 9.1.1.

11. Imposition of network limits on distributed generation: This is attributed to current or potential technical impacts on the network. In some cases this may be justified, however a recent CSIRO report concluded that "This is a conservative response to a lack of information about network problems intermittent renewable generation might cause and/or concerns about the mitigation measures required to address them, including cost and availability" (CSIRO, 2012).

Discussions are also ongoing regarding utility control of grid-connected PV systems - curtailment or reduction of PV exports to the grid if/when required, and placing limits on net metering, such that all PV generation is considered bulk supply and cannot be netted against customer usage. Neither of these options has yet been implemented.

Although all these actions are entirely understandable from the utilities' perspective, they serve to illustrate the relatively minor changes that are currently being considered, and their focus on maintaining utility revenue through conventional means. Both TOU tariffs and higher demand charges should send price signals that will help reduce demand peaks and therefore network costs. They are also likely to increase revenue to utilities. While the types of TOU tariffs applied to residential customers will not be particularly helpful to PV, they should help drive the uptake of storage technologies as well as DSM. Note, however, that implementation of TOU tariffs does not currently have political support and so, along with deployment of interval meters, which are an essential hardware component for TOU pricing, have relatively slow levels of promotion and uptake. Higher fixed daily charges, on the other hand, only serve to maintain utility revenue and in fact decrease the relative effectiveness of usage charges in driving EE and DG. Such charges would also be in conflict with the National Electricity Rule clause 6.18.4(3) that "however, customers with micro-generation facilities should be treated no less favourably than customers without such facilities but with a similar load profile".[20] They also illustrate how discriminatory some utilities are against DE, given that according to the ESAA's own data, owners of PV systems receive just one eleventh of the cross subsidy received by owners of air conditioners (ESAA, 2012; ESAA, 2013). The selling of PV and the use of home energy portals are certainly a step in the right direction towards retailers' active involvement in the DE market. The low payments for PV export are interesting in the light of these same retailers selling PV systems, although make sense given that the sale of PV systems is profitable in its own right, and the low payments for export serve to limit the negative financial impact of PV generation – both directly (for the retail arm) and indirectly (for the generators) by limiting the system size. The network limits applied to distributed generation may not be so much to maintain revenue streams as to address technical issues, and so are less relevant here, although they may also be the easiest way for incumbents to deal with a 'disruptive' technology.

Further evidence of DNSPs' lack of focus on demand side management is the low level of interest in the Demand Management Incentive Scheme (DMIS).[21] Part A of the DMIS is the Demand Management Innovation Allowance (DMIA), which can be used to cover the costs of research, development and deployment of demand management. The DMIA is allocated over the 5 year Determination period, and with only about 1 year left, ActewAGL, Ausgrid and Endeavour have each spent less that 15% of their allowance, while Essential Energy has spent 41%. SA Power Networks, Energex and Ergon each have about 2 years left, with Ergon having spent about 20% and SA Power Networks and Energex having spent zero and 1% respectively (AER, 2013a). Part B of the DMIS is used to compensate DNSPs for foregone revenue as a result of demand management implemented through Part A. No compensation was claimed for the 2010/11 period (AER, 2012), and the report

[20] http://www.aemc.gov.au/Media/docs/NERv29-4081d270-e7f4-45d5-a998-b51860f6ea80-1.PDF

[21] The DMIS has now been renamed the Demand Management and Embedded Generation Connection Incentive Scheme (DMEGCIS).

for the 2011/12 period does not mention any such claims. Thus, even where there is no expense to the DNSPs, and they will be compensated for lost revenue, they appear to have little inclination in driving uptake of DSM.

It is worth noting, however, that the lack of interest in the DMIS may be because it is not a true incentive scheme where the DNSP is regulated under a WAPC, because the DNSP won't receive any benefits, only compensation for losses. DNSPs have also indicated that the lack of funding provided under the DMIA reduces its effectiveness (AER, 2013b). However, it is also worth noting that, according to the AER, "the DMIA is not intended to replace or substitute for demand management initiatives currently being carried out as part of a DNSP's normal operations, and is applied in addition to the obligations on DNSPs to consider non-network alternatives to capex or opex imposed by the NER" (AER, 2009, p260).

Possibly in response to a state government requirement that DNSPs prepare demand side plans (OG, 2012), Energex has taken a novel approach to implementing demand management by including a 5 year DSM plan into its most recent regulatory proposal. This plan was approved by the AER and allows Energex to secure a portion of the projected long-term and upstream benefits for itself (Wright and Burne, 2012) – which highlights the importance of providing a direct financial incentive for them to implement DSM.

One area of concern with DNSPs undertaking DSM, or any form of DE for that matter, is that they may have a competitive advantage over 3rd parties wishing to do the same thing. This is discussed further in Section 9.1.2.

5.2. Responses by government

Although a comprehensive review of government responses is beyond the scope of this report, the following firstly summarises two of the most significant from the point of view of DE: The Power of Choice (PoC) Review by the Australian Energy Market Commission (AEMC), and the Senate Select Committee on Electricity Prices. While they both aim to reduce electricity costs for consumers, they also focus on giving customers options to manage their electricity through various DE options, and highlight the problems faced by utilities should reductions in electricity use continue to occur. The need for such government responses implicitly recognises the fact that the current incentives in the National Electricity Rules are insufficient to drive consideration of demand side options as alternatives to network augmentation.[22] Although both these reviews also focussed on a broad range of regulatory issues relevant to high electricity prices, here we focus on those aspects most relevant to the uptake of DE.[23]

The PoC Review assessed the market and regulatory arrangements that are needed to facilitate efficient investment in, and operation and use of, 'demand side participation' (DSP)[24] in the NEM, with the aim of reducing electricity costs for consumers. As outlined above, network expenditure is one of the main drivers of increased electricity costs, and peak demand is projected to continue to increase in all Australian states and territories despite recent decreases (Ernst & Young, 2011). The

[22] Section 5.6.2 of the National Electricity Rules states that when distribution and transmission network operators are planning to augment the network, they must first consider whether demand-side options can deliver the same outcome at a lower cost. Sections 6.5.6, 6.5.7, 6A.6.6 and 6A.6.7 in the National Electricity Rules provide the AER with discretion to reject proposals for capital expenditure on network infrastructure if non-network alternatives would be more economically efficient.

[23] For example, these reviews and PC (2013) also referred to the impacts of reliability standards, ownership of distribution businesses by state governments, the incentive to expand their regulated asset base, the WACC calculations, capex expenditure in excess of regulated allowances, etc.

[24] DSP refers to energy efficiency, demand side management and distributed generation, and so is the same as distributed energy.

effectiveness of measures to reduce electricity use in order to reduce customer costs will be limited by the need to pay for the networks' capital costs. The Final Report for the PoC Review included a number of recommendations that reflect the difficult task of both reducing costs for consumers while maintaining payments for networks (AEMC, 2012). One of the Report's main points regarding EE is that: "Schemes need to consider and address the secondary impacts that they are likely to have on the electricity market and its participants. It is important that these schemes do not impose unintended impacts on the market, for example, upward pressure on electricity prices" (AEMC, 2012, page 242). This refers to the possibility that EE that simply reduces average demand, with or without reducing peak demand, will reduce the distribution network's utilisation and so increase the 'per unit' costs of distribution prices. Thus, rather than focussing on broad-based EE measures, the Report has emphasised (i) ensuring that price signals reflect network costs (e.g. via time of use tariffs),[25] then (ii) ensuring that consumers are exposed to those price signals and have access to the information and technology required to respond. As previously mentioned, there is currently little political will to implement TOU tariffs.

The intention is that this might not only produce a short term increase in revenue (paid mainly by large residential and commercial consumers)[26] but also reduce peak demand and so reduce future network costs – and hence costs to consumers. The emphasis is clearly on reducing long-term costs: "…. it is important that the arrangements for managing expenditure changes (the first round effects) do not undermine the ability to capture the benefits of better asset utilisation and lower system costs (second round effects)" (AEMC, 2012, page viii).

In addition to recommendations to better align price signals with network peaks, and in order to further protect network operators' income, the Report lists four options to decouple network income from changes to energy use. Their effectiveness, or rather, lack of effectiveness, is discussed in Section 9.1.1.

Other proposals in the Report are: a particular demand response mechanism,[27] measures to promote increased competition, that consideration should be given to the benefits of network operators owning and operating DG, and that AEMO's role in short and long-term demand forecasts be clarified and enhanced.

The demand response mechanism referred to in the Report is currently being developed by the Demand Response Working Group. It would essentially mean that participating customers who implement non-scheduled demand side measures would be paid the difference between the current spot price and the retailer's contracted price. While this may be useful, it is interesting to note that the consumer is not paid for reducing network peaks and so reducing augmentation costs – which reflects the Report's emphasis on maintaining revenue for network operators.

The measures proposed to increase competition are certainly a step in the right direction for a distributed energy market. Together they serve to open up the market to more competition from third parties and, importantly, may allow network operators to do more than just build networks. Specifically, they require that:

1. Consumers be able to source their electricity from, and sell their DSP to, entities other than their retailer (also known as portability),

[25] According to the recently released Energy White Paper, energy-intensive domestic devices, such as air conditioners and large flat screen TVs are the main drivers in peak demand growth, with a 2kW air conditioner that costs $1,500 estimated to impose costs of $7,000 on the electricity system (DRET, 2012).

[26] Under the PoC recommendations, smaller and financially vulnerable consumers would have the option of remaining on a flat tariff.

[27] More details at http://www.aemo.com.au/About-the-Industry/Working-Groups/Demand-Response-Mechanism-Working-Group

2. A new category of market participant for non-energy services be introduced in the National Electricity Rules (NER) to unbundle the sale and supply of electricity from non-energy services, such as ancillary services,[28]
3. The National Energy Customer Framework be amended to include a framework which governs third parties (non-retailers and non-regulated network services) providing energy services to residential and small business consumer.

Allowing network operators to own and operate DG could have significant benefits, not only to provide network support but also to help reduce generation costs at peak times. However, although the AEMC suggest that ring fencing arrangements could be put in place to avoid network operators preferring their own DG rather than what might actually be a least-cost option, it is not clear how this would work in practice. Non-competitive behaviour could extend beyond the use of regulated revenue streams to support DG, to include access to network information and could even include DNSPs distorting network needs to support the construction of their own units. These issues are discussed in more detail in Section 9.1.2.

Demand forecasting is used by AEMO for a variety of processes including volume dispatch and pricing, as well as system planning and investment decisions. DG, EE and DSM do not bid into the market, and therefore can only be estimated, and so as more is deployed, forecasting becomes increasingly difficult yet more important (AEMC, 2012). Enhancing AEMO's ability to forecast demand would be helpful for a distributed energy market because it will provide information on the price-responsiveness of demand (ideally in particular regions) as well as how demand is affected by weather (both energy use and DG). This sort of information will be helpful both at the network planning stage (especially where Integrated Resource Planning is incorporated, as discussed in Section 8), and during operation – for example, it will provide participants with information they can use to better target their services to minimise demand peaks.

The Senate Select Committee on Electricity Prices was another major recent review into the causes of high electricity prices, and culminated in the report 'Reducing energy bills and improving efficiency' (SSCEP, 2012). This report's primary conclusion was that the main reason for high electricity prices is inefficient over-investment in electricity networks driven by perverse incentives inherent in the regulatory environment. It recommended a range of changes to limit the incentives for networks to over-invest in capacity and for such investment to be reviewed ex-post. An even more recent report by the Productivity Commission agreed with these findings (PC, 2013.)

In addition, in recognition that increases in peak demand were driving prices higher, a series of recommendations in the Senate Select Committee report correspond to those of the PoC Report, i.e. cost-reflective pricing with protection of vulnerable consumers, technologies to enable responses to these prices, such as smart meters, the provision of reliable information to consumers, and changes to the regulation and operation of the Australian NEM that would encourage and allow consumers, or authorised third parties, to sell their demand response in the wholesale electricity market. It also focussed on the network design, connection and cost barriers to embedded generation feeding electricity into the grid and so recommended there be appropriate regulatory and operational reforms to overcome them.

In summary, the PoC Report and the Senate Select Committee's report agree that electricity prices are becoming too high and need to be reduced. They emphasise the need to pay for networks, and that demand peaks should be reduced as they are a major contributor to price rises. Both support cost-reflective pricing, information and increased competition, all of which should significantly assist the development of a distributed energy market. However the reports also diverge slightly, with the former focussing more on maintaining the network operators' revenue

[28] These include market ancillary services, reactive power, and network control support ancillary services.

through existing business models, and viewing DG and EE that doesn't target demand peaks as a risk to that revenue. The latter emphasised the cessation of inefficient over-investment by network operators and enabling the connection of embedded generation.

However, and most importantly, both are limited in three particular areas. The first is the very limited attention given to the consideration of introducing demand-side options into the network planning process, the second is the treatment of DG, EE and DSM as 'add-ons' to the existing market (which remains essentially unchanged), and the third is the lack of practical suggestions for decoupling network operators' revenue from electricity use. These are discussed in Sections 8.1 and 9.1.1 below.

Other government responses worth mentioning are the Queensland Competition Authority's proposal that gross metering should be compulsory for all PV systems and they would be paid an optional rate of around 8c/kWh for all generation, and their proposal that all owners of PV systems should be placed on Tariff 12. Both recommendations were intended to shore up revenue for DNSPs. Interestingly, the gross metering proposal was strongly opposed by the majority of submissions, including those from retailers, distributors, PV associations and customer groups. They generally argued that gross metering would unfairly force PV customers to sell all of their PV energy at a low rate and then pay a higher retail price for all their usage (QCA, 2013). The recommendation to force PV owners onto Tariff 12 is particularly interesting. Tariff 12 is a ToU tariff that has a very high fixed daily charge ($78.66/quarter compared to $26.20/quarter Tariff 11, a flat tariff). Despite acknowledging that forcing PV owners onto Tariff 12 would be inconsistent with Clause 6.18.4(b)(4) of the National Electricity Rules,[29] and showing that it would, if anything, increase the cost of the solar FiT to all customers, they recommended that government should consider moving PV customers to this tariff because it would help stop them "avoiding a portion of the true cost of their network access" (QCA, 2013, page vi). This refers to the perception that by drawing less electricity from the grid, PV owners are avoiding paying their fair share of network costs. Apart from the fact that this shows a clear bias against PV systems by not focusing on the activities that actually drive peak demand, and therefore high network costs (eg. air conditioners), to be non-discriminatory, this approach would also have to be applied to anyone that reduces their energy use by other means, including through SWHs or other EE options.

[29] It requires that retail customers with PV should be treated no less favourably than customers without PV but with a similar load profile.

6. The Need for Fundamental Regulatory Change

As discussed in Section 4, utilities worldwide are now recognising that DE is 'disruptive'. As discussed in Section 5, government and utility responses to date have focussed on maintaining the current utility business models, with relatively minor changes to the regulatory environment.

However, when 'disruptive technologies' such as DG, EE and DSM are introduced into a well-established industry (e.g. the Australian NEM), by their very nature, they don't simply integrate seamlessly, but exert change in doing so – as is already occurring according to the government reviews and reports discussed above. In addition, given that DE technologies will not be completely replacing the existing technologies, but will be integrated with them, the new regulatory environment will need to accommodate both. This means that the existing industry will experience change not only as a direct result of the operations of the DE industry, but as a result of changes to government regulation.

This effect is well illustrated in Figure 29. According to Schleicher-Tappeser (2012), it highlights the fact that the conventional electricity industry is characterised by a relatively hierarchical structure, controlled by a small number of actors with a limited number of choices, and where customers could be treated as statistically predictable units. In contrast, DE is enabling end-users with a significant number of alternatives that is resulting in a system with much more self-organisation growing from the bottom up through a complex process involving not only technical innovation but also strong economic, institutional, and political interests. As a result, organisation and chaos theories may be a more appropriate way to describe the dynamics than the assumptions of conventional planning.

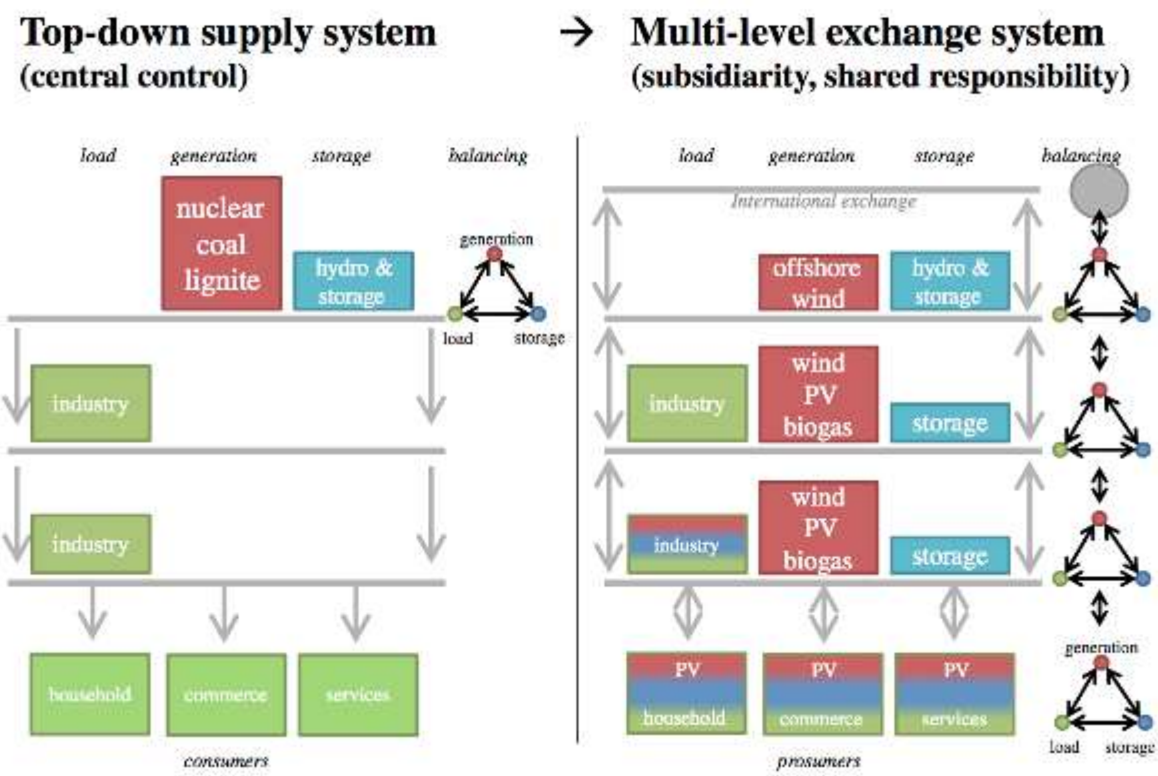


Figure 29. Transformation of the electricity system – schematic representation (Schleicher-Tappeser, 2012)

Schleicher-Tappeser (2012) goes on to say:

> *"While a new system logic is growing bottom-up and getting into conflict with the old top-down logic it seems urgent to develop a regulatory framework for a comprehensive multi-layered system aiming at the optimal combination of resources at all scales respecting the principle of subsidiarity……. Since two key elements of different categories – power generation technologies and customers – are fundamentally changing their roles and behaviours, minor adjustments of the system are probably not sufficient…….. While for years ''prudent'' or ''moderate'' public and private policies meant not to bet too much on a desirable but difficult transformation, today prudence means to be prepared for unexpectedly rapid change in a turbulent environment."*[30]

The Electricity Innovation Lab (e-Lab) is US-based and "brings together thought leaders and decision makers from across the U.S. electricity sector to address critical institutional, regulatory, business, economic, and technical barriers to the economic deployment of distributed resources" (eLab, 2013, p2). It recently released a discussion paper that concluded:

> *"Already, the growing role of distributed resources in the electricity system is leading to a shift in the fundamental business model paradigm of the industry. The electricity industry is evolving from a traditional value chain to a highly participatory network or constellation of interconnected business models at the distribution edge, where retail customers interface with the distribution grid. ….. Existing electric utility business models, however, are poorly adapted to tap the potential value of distributed resources to meet societal demands for cleaner, more resilient, and more reliable electricity supply. …. Achieving this transition may require transformative, rather than incremental, changes in utility business models."*

A recent report by the McKinsey Global Institute 'Disruptive technologies: Advances that will transform life, business, and the global economy' (Manyika et al., 2013), includes both energy storage and renewable energy, and the website promotion states:[31]

> *"The potential benefits of the technologies discussed in the report are tremendous—but so are the challenges of preparing for their impact. If business and government leaders wait until these technologies are exerting their full influence on the economy, it will be too late to capture the benefits or react to the consequences."*

Figure 30 illustrates how the priorities for matching production and consumption change as more renewable energy, both centralised and distributed, enters a conventional electricity system. It is clear that as DE penetration increases, the focus changes from management of centralised production to management of consumption and storage (Schleicher-Tappeser, 2012). As discussed, this involves more than just technical changes, but also changes to the regulatory environment.

[30] Subsidiarity is an organising principle stating that a matter ought to be handled by the smallest, lowest, or least centralized authority capable of addressing that matter effectively - Wikipedia

[31] See http://www.mckinsey.com/insights/business_technology/disruptive_technologies

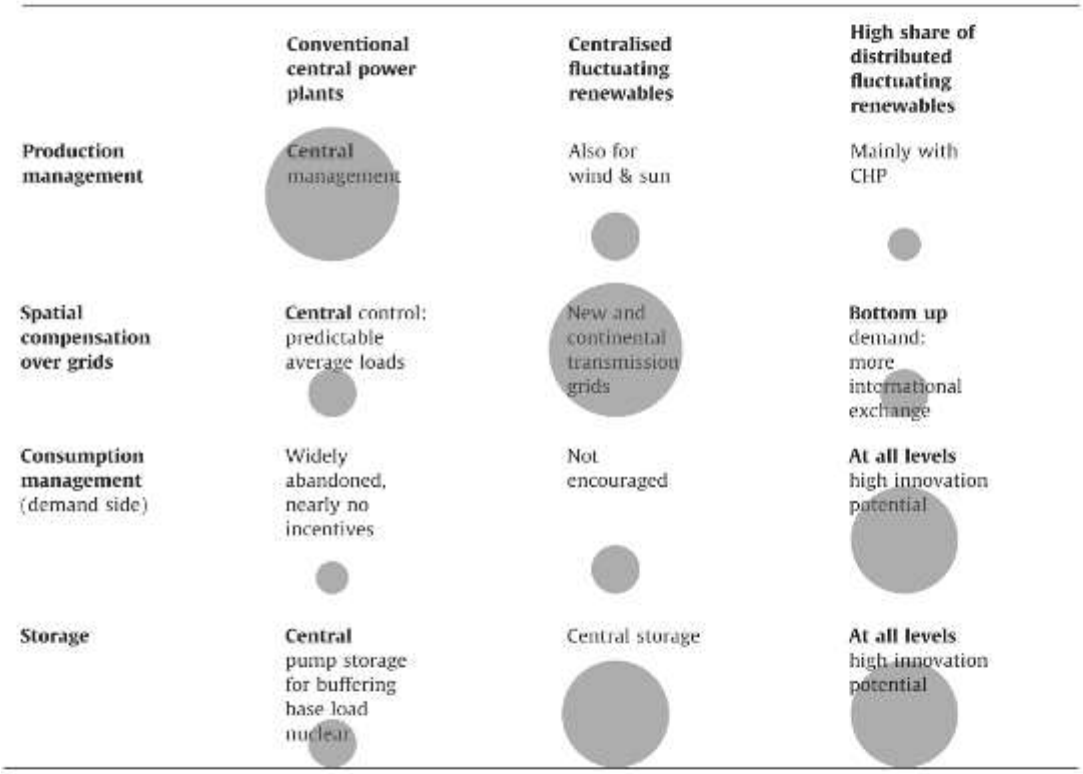


Figure 30. Approaches for matching production and consumption of electricity (Schleicher-Tappeser, 2012)

The following sections focus on regulatory changes that are likely to be required for the NEM, and in slightly modified form as appropriate, for the WA SWIS and NWIS. Over the longer term, it is likely that much more significant changes to the electricity market will be required than apparently envisaged by the various government reviews. Rather than having the existing market with DG and EE integrated where possible, a fully integrated distributed energy market may need to be developed. It is important to recognise that, as discussed above, continued uptake of DE is likely to be inevitable, and so such changes are needed to not only optimise DEs contribution to least-cost energy services, but to enable the existing electricity industry to adapt their business models and so transition to the 'new normal'.

7. The Need for Full Competition in a DE Market

A fundamental principle of a distributed energy market as defined here is that of equal competition between supply-side and demand-side options at all levels: generation, networks and retail. There should also be competition between supply-side options and between demand-side options. For a distributed energy market these types of competition are illustrated in Table 5.

Table 5. Types of competition possible in the wholesale, network and retail markets

	Wholesale	Networks	Retail
Demand vs demand[32]	EE/DSM vs EE/DSM	EE/DSM vs EE/DSM	EE/DSM vs EE/DSM
Supply vs demand	Centralised and DG vs EE/DSM	Augmentation/capital replacement and DG vs EE/DSM	Electricity sales and DG vs EE/DSM
Supply vs supply	Centralised vs DG, DG vs DG	Augmentation/ capital replacement vs DG	Electricity sales vs DG, DG vs DG

Different approaches are required to achieve full competition in each of these markets.

Wholesale market: The wholesale market operates on a competitive basis, and the factors that directly influence distributed energy's ability to compete with wholesale generation occur in the network and retail markets. Therefore, the wholesale market is not a focus here, but will nonetheless be affected if a national market is established. An important caveat is that state governments in NSW and Qld wish to sell their black coal-fired generators, which could reduce their support for measures that may reduce their sale value, such as a price on carbon, the RET, as well as the uptake of DG and EE. Thus, the operation of the wholesale market can indirectly affect the uptake of DE.

Networks: Networks are regulated monopolies, meaning that, in the absence of effective market competition, price control is introduced through the Network Determination process.[33] However, it is clear from the PoC Review and Senate Select Committee on Electricity Prices reports, among others, that the current network planning processes are insufficient to drive significant alternatives to network investment. The Network Determinations essentially lock in network investments for 5 years, and so it is important that effective competition between supply and demand side options occurs during the network planning stage. In addition, in order for the market to be able to incorporate new technologies and to respond to changing circumstances over time, full supply/demand competition also needs to occur on a day-to-day basis, not just during long-term

[32] While DSM doesn't happen directly in either the wholesale or network markets, it does affect the operation of these markets.

[33] In the Australian National Electricity Market, the Australian Energy Regulator conducts 5-yearly Network Determinations to assess the network's capacity requirements and associated costs that can be passed through to end-users. While not referred to as a Network Determination in Western Australia, the Economic Regulation Authority produces final decisions that are the equivalent.

planning processes. This would allow 3rd parties to implement DE to manage loads at any time, and hence reduce the need for network expenditure at the next determination period.

Retail markets: While Price Determinations occur for the retail markets in most jurisdictions, they essentially just pass through the network costs according to the Network Determinations, set a price that can be passed through for wholesale and related costs, and apply a retailer margin. Customers are also offered market-based tariffs from a number of different retailers in these markets,[34] and so, rather than introducing competition during the Price Determination process, the focus should be on expanding this competition from essentially being between tariffs to being full competition between all supply and demand-side options, again on a day-to-day basis.

In summary, this report recommends establishing a DE market through:

(iii) Proposing Integrated Resource Planning be used in the network planning processes (covered in Section 8), and

(iv) Driving full competition between all supply and demand-side options on a day-to-day basis (covered in Section 9):

[34] Note that there is still some uncertainty about whether the retail markets can currently be classed as fully competitive (for example IPART, 2011). Also, not all jurisdictions (e.g. South Australia) offer time of use tariff options.

8. Incorporating Integrated Resource Planning into the Network Planning Process

Under the National Electricity Rules (NER), DNSPs are required to demonstrate that efficient non-network alternatives to network capital expenditure (capex) and operating expenditure (opex) have been satisfactorily considered in the development of their expenditure proposals for each Determination (AER, 2012). However, it is clear from recent government reviews (for example SSCEP (2012), as discussed in Section 5.2), that this requirement has been insufficient to drive uptake of alternatives and so reduce network costs. This is also the case internationally, where for example in the US, “economic incentives in many states and system planning culture have made ‘poles and wires’ (or T&D hardware) the default solution to T&D-related reliability issues almost everywhere” (Neme and Sedano, 2012, p21).

During the course of this project, on 1 January 2013, changes were made to the NER that included the development of a Regulatory Investment Test for Distribution (RIT-D) that will replace the existing Regulatory Test for distribution investments. The draft RIT-D and application guidelines were released in June 2013, the final versions will be released by 31 Aug 2013, and they will come into effect on 1 January 2014 (AER, 2013c).

RIT-D is a basic type of Integrated Resource Planning (IRP), which is a core recommendation of this report. The following firstly describes IRP then describes how it differs to the process currently used for network augmentation. It then provides examples of network-focused IRP processes in the US before describing best practice IRP and its additional benefits. It concludes by describing RIT-D and assessing how this compares to best practice IRP.

IRP can be used to formalise the incorporation of DE into the network planning and investment process. Currently used in some form in 40 states of the United States (see Figure 31 and Figure 32), this process was first developed for vertically integrated power systems that included a component that was a natural monopoly and so was regulated (e.g. electricity networks) (Tellus, 2000). In most cases in the US, the emphasis is not on networks, but on using demand side resources to reduce the need for electricity generation. However, as discussed in Section 8.1, there are a number of US states where IRP approaches are used specifically during the network planning process.

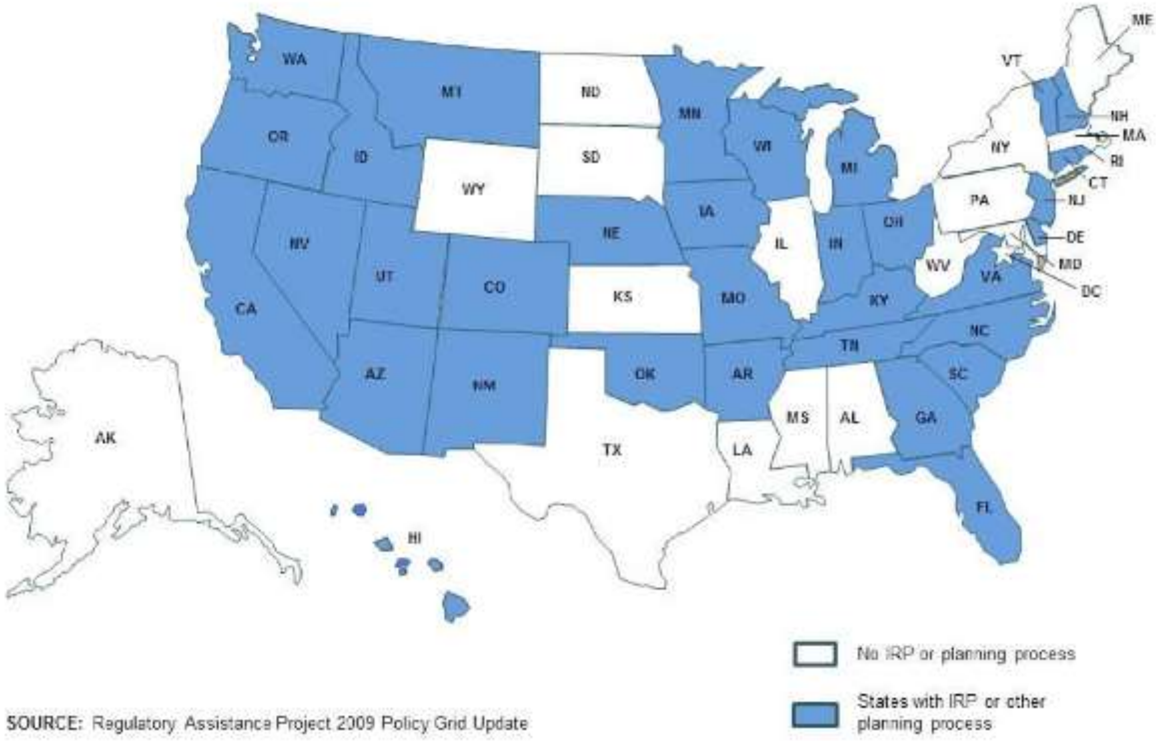


Figure 31. US States with Integrated Resource Planning of Similar Processes (SLEEAN, 2011)

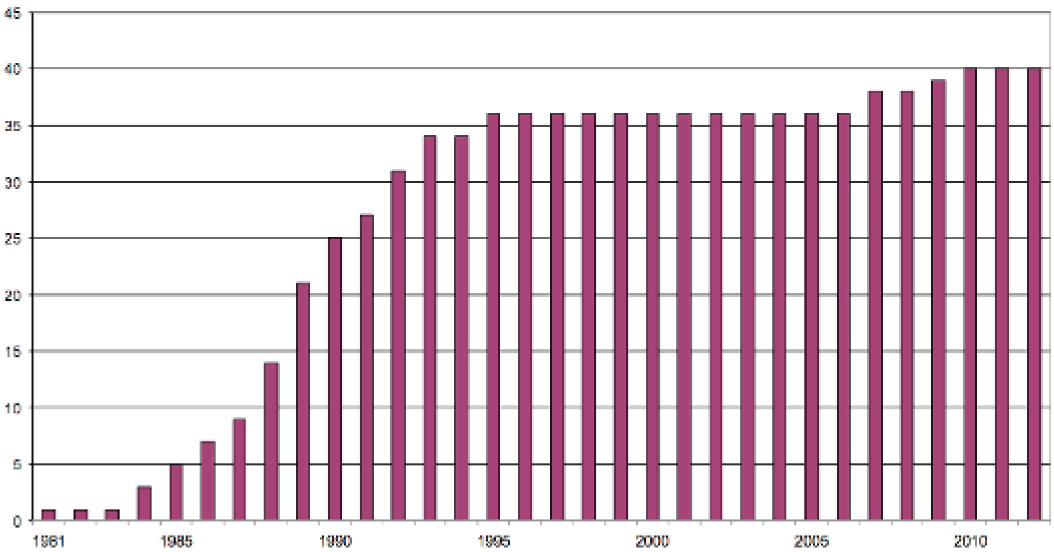


Figure 32. Number of US States requiring Integrated Resource Planning (ACC, 2012)

While there are variations on the IRP process, the core principles are that it (Tellus, 2000):

5. Considers a full range of feasible supply-side and demand-side options and assesses them against a common set of planning objectives and criteria;
6. Is transparent and participatory throughout, meaning that parties other than the network operator can propose both supply-side and demand-side options;

7. Is subject to oversight by an independent (normally government) body; and
8. Is subject to regular review.

The role of the independent body is critical. According to D'Sa (2005, page 1279), "The authority should be responsible for the planning framework, for imposing the need for least-cost energy services, for monitoring the implementation and renewal of plans, for facilitating data accumulation, and to serve as an acceptable conduit for timely two-way communication between stakeholders".

In the US, IRP occurs in a number of different forms based on the nature and degree of involvement of the independent body, the state's Public Utility Commission (PUC), which, in increasing order of effectiveness at incorporating demand side participation, may:

A. Acknowledge receipt of IRPs developed by utilities
B. Approve IRPs filed by utilities, with modifications if necessary[35]
C. Develop an IRP based on data provided by utilities
D. Convene an IRP process with opportunities for stakeholders to intervene prior to a regulator decision

Of the above, it is difficult to see how types C and D could be applied in Australia because it would mean the regulator had to be involved in the day to day planning and operations of the network operator.

The steps in a best practice IRP process are illustrated in Figure 33 and are to:

1. Establish objectives;
2. Survey energy use patterns and develop demand forecasts;
3. Investigate electricity supply-side options;
4. Investigate demand-side options;
5. Prepare and evaluate supply-side plans;
6. Prepare and evaluate demand-side plans;
7. Integrate supply-side and demand-side plans into candidate resource plans (which can involve a number of iterative steps to reach an optimal supply/demand outcome);
8. Select the preferred plan; and
9. During implementation of the plan, monitor, evaluate, and iterate

Thus, IRP can be used to identify areas where DG is cost-effective and requires the network operators to acquire it through a competitive procurement process. This helps to develop a competitive and transparent distributed energy market, and so opens it up to new entrants.

[35] Both the RIT-D discussed in Section 8.4 is this type of IRP, and the approval for a 5 year DSM plan in Energex's most recent regulatory proposal could be said to be a limited form of this type of IRP.

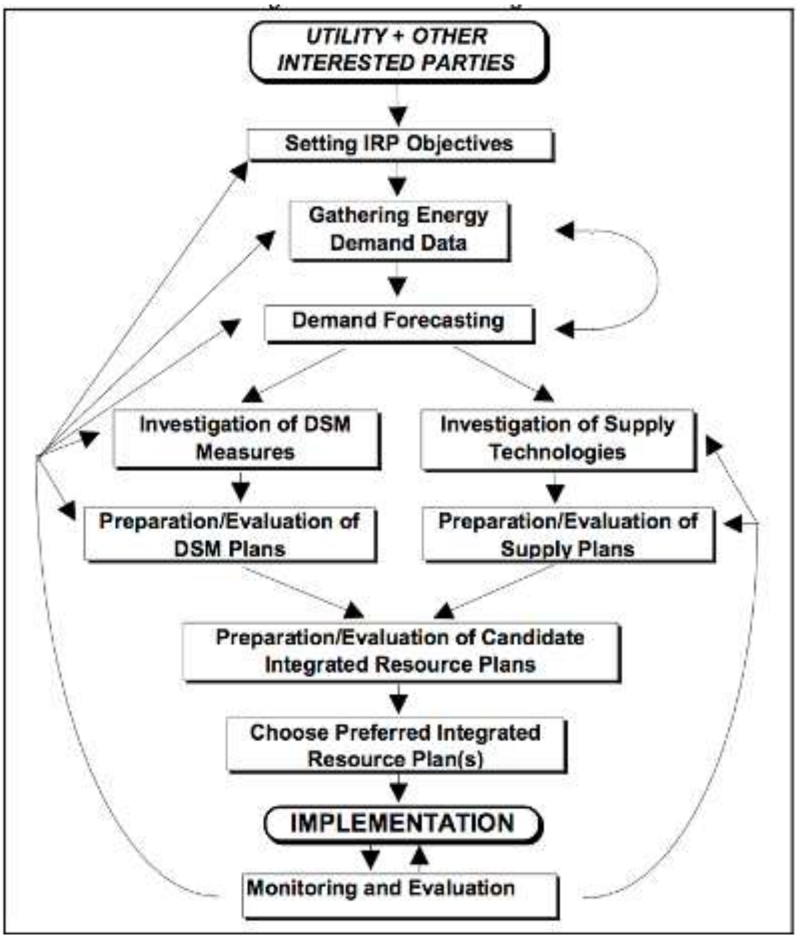


Figure 33. The Integrated Resource Planning process (Tellus, 2000)

This compares to the existing process for network augmentations where the network operator generally designs the default network solution, then possibly calls for alternatives, then assesses them through an internal procedure – see Figure 34.

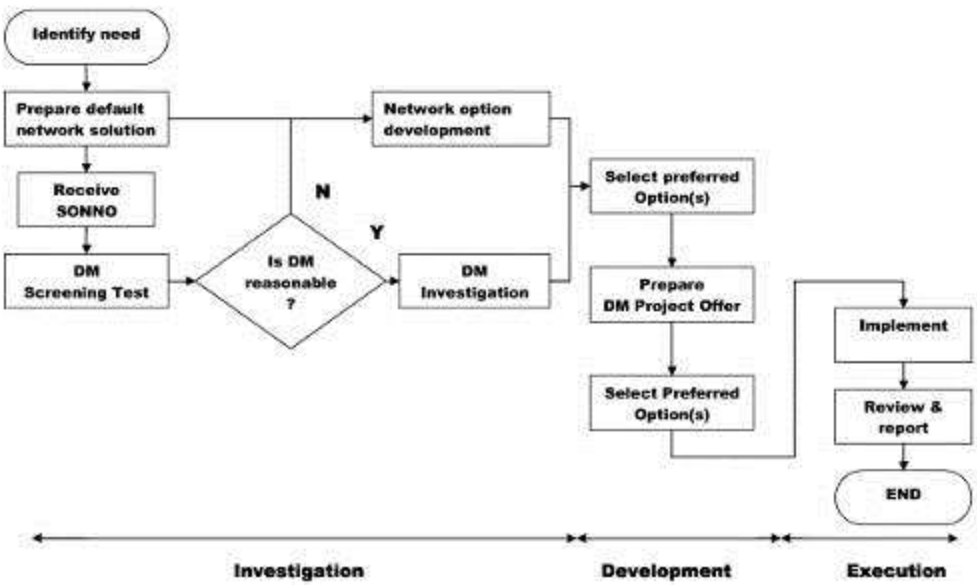


Figure 34. Simplified diagram of Ausgrid's demand management process (Ausgrid, 2012)

8.1. Examples of Network-focussed IRP processes

The following examples are provided to showcase where IRP or a similar process has been used to promote the use of DE options as alternatives to network investment.

8.1.1. Con Edison

Con Edison is an electric distribution utility in the New York City area.[36] Although it was not subjected to an IRP process, in 2003 it launched a targeted demand management program focused on the parts of its network that were nearing capacity. This was on the basis that efficiency would be implemented as the one and only solution where it proved to be more cost-effective than transmission and distribution infrastructure. After estimating the cost of network solutions to forecast capacity constraints, they issued a request for proposals for energy efficiency services targeted to address the same constraints. Where viable bids were received at a cost less than the cost of the infrastructure project, energy efficiency was procured through a contract. Otherwise, the infrastructure project was executed. Over the next five years, the contracted energy service companies succeeded in procuring 89 MW of targeted savings at a benefit/cost ratio of 2.8. These efforts saved Con Edison over USD223 million in capital costs (SLEEAN, 2011).

8.1.2. Rhode Island

In 2006, Rhode Island adopted a 'System Reliability Procurement' policy that requires utilities to submit system reliability procurement plans every three years. While not strictly an IRP, the guidelines stipulate that utilities must incorporate into their network planning process (for the following 3 years) alternatives including energy efficiency, distributed generation, and demand response – whenever the need for augmentation:

- Is not based on an asset condition;
- Will likely cost more than USD 1million to address;
- Would require no more than a 20% reduction in peak load to defer; or
- Would not require investment in a 'wires solution' to begin for at least 36 months.

In such cases, the utility must develop an implementation plan that includes an analysis of financial impacts, risks, and the potential for synergistic benefits for both network and non-network alternatives, and this must be approved by the Public Utilities Commission (Neme and Sedano, 2012).

8.1.3. Vermont

Vermont's Act 61 enforces IRP by stating that all available resources – transmission, strategic generation, targeted energy efficiency, and demand response resources – should be treated comparably in analysis, planning, and access to funding. Utilities must have minimum 10-year planning horizons, with plans to be filed at least every three years, in order to allow sufficient time to plan and implement more cost-effective non-network solutions. In addition, prior to the adoption of any transmission system plan, a utility preparing a plan shall host at least two public meetings at which it shall present a draft of the plan and facilitate a public discussion to identify and evaluate non-transmission alternatives (Neme and Sedano, 2012).

Specifically, the plan has to:

- identify existing and potential transmission system reliability deficiencies by location

[36] On January 1, 1998, Con Edison changed from a vertically integrated utility into a holding company with regulated and unregulated subsidiaries.

within Vermont;

- estimate the date, and identify the local or regional load levels and other likely system conditions at which these reliability deficiencies, in the absence of further action, would likely occur;
- describe the likely manner of resolving the identified deficiencies through transmission system improvements;
- estimate the likely costs of these improvements;
- identify potential obstacles to the realization of these improvements; and
- identify the demand or supply parameters that generation, demand response, energy efficiency or other non- transmission strategies would need to address to resolve the reliability deficiencies identified.

8.2. Best-practice IRP

It is clear there is a fair amount of variation between different IRP processes, in terms of both their design and their effectiveness. According to SLEEAN (2011) and D'Sa (2005), best-practice IRP includes the following elements:

1. **Load:** include a range of possible load forecasts, not just the one most likely forecast, with probabilities assigned to each forecast for risk analysis purposes.
2. **Supply-side options (which can include networks):** include a range of possible costs, considering uncertainties in the availability and costs of raw materials and skilled labor, construction schedules, and future regulations.
3. **Demand-side options:** create levelised cost curves for demand side resources that are comparable to the levelised cost curves for supply side resources.
4. **Modeling:** consider multiple scenarios to identify a portfolio of resources that has low costs and risks across most or all scenarios, instead of automatically choosing the one portfolio that looks best under the reference case. Thus, planners can choose a resource portfolio that is 'robust' in the sense that its average cost across all scenarios is low, and in very few scenarios does it fare much worse than other possible portfolios.
5. **Environmental and other regulations:** include the potential costs of a range of possible future regulations.
6. **Stakeholder participation:** provide opportunities for consumer advocates and other stakeholders, including research organisations, to review the modeling assumptions and the list of scenarios to be modeled and suggest changes or additions.
7. **Scale:** where utilities operate where the cost and value of supply side and demand side resources cross territory and state boundaries, the IRP should ideally be performed at the largest scale possible, provided that it is done in a way that complements rather than supersedes more localized planning.

8.3. Additional Benefits

Experience with IRP has illustrated that, in addition to achieving least-cost outcomes, it has additional benefits.

Social and environmental: IRP can help achieve social and environmental objectives, both implicitly (eg. by helping to provide least-cost electricity to disadvantaged people), and explicitly. Explicit objectives may be in qualitative terms and can include minimisation of environmental impacts, use of local resources, social benefits such as increased electrification of disadvantaged areas and minimising amenity impacts of infrastructure, and local employment and capacity building (D'Sa, 2005; Tellus, 2000).

Risk reduction: According to D'Sa (2005), IRP has been considered a risk-reduction or reliability-improvement strategy. One example is that IRP that incorporates DSM can reduce demand volatility, which reduces reserve requirements, and has a lower risk of outages. Another example is that DE options generally have much shorter lead times which means that utilities and customers benefit from quicker answers to changes in requirements.

More accurate network costs: To determine the allowable income for DNSPs, the current Determination process relies solely on network cost information provided by the network operator to the regulator. Due to information asymmetries and a principal agent problem[37] between the regulator and the DNSPs, arriving at accurate network costs can be problematic (Vogel, 2009), However, in an IRP process all costing must be transparent (at last to the independent arbiter) and subject to competition from third parties that bring market forces to bear in the costing process. As a result, the forecast of network costs is more likely to be accurate, and likewise, the network operators' regulated revenue cap is also more likely to be accurate.

Helps overcome problems with the Regulated Asset Base (RAB): Currently, network operators returns are based on the size of their RAB, meaning they will oppose alternatives to network augmentation that don't increase their RAB. Under IRP, this is not an issue because the choice between network augmentation or the alternatives is made by an independent party – at least during the planning phase (but not during day-to-day operations).

Thus, here we propose that IRP could be the foundation for introducing more market-based competition between supply and demand side options into networks during the network planning process. The introduction of such competition on a day-to-day basis is discussed in Section 9.

8.4. RIT-D: IRP in Australia

In Australia, IRP has been applied to the planning of other large infrastructure systems, and has become an important component of water supply planning since the early 1990s (ISF, 2011). The RIT-D that is due to come into force in Australia on the 1 Jan 2014 is a basic form of IRP. The RIT-D requires DNSPs to consider and assess all credible options before it makes an investment decision to address an identified network need. According to Clause 5.17 of the NER:

> *"The purpose of the RIT-D is to identify the credible option that maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the NEM (the preferred option). The RIT-D aims to promote efficient distribution investment in the NEM and to ensure that there is greater consistency, transparency and predictability in distribution investment decision making."*

The general steps for applying the RIT-D are to:

1. Identify the need for the network investment
2. Identify a set of credible options to address the need
3. Apply a set of reasonable scenarios
4. Quantify the expected costs of each option in the different scenarios
5. Quantify the expected benefits of each option in the different scenarios

[37] Relates to the difficulties in motivating one party (the agent), to act in the best interests of another (the principal) rather than in his or her own interests.

6. Rank each credible option by its expected net economic benefit to identify the credible option with the highest expected net economic benefit as the preferred option

A RIT-D proponent must consider all feasible non-network options such as the following, including combinations that can form an integrated solution (AER, 2013c, p28):

- "any measure or program targeted at reducing peak demand, including:
  - improvements to or additions of automatic control schemes such as direct load control
  - energy efficiency programs or a demand management awareness program for consumers
  - installing smart meters with measures to facilitate cost-reflective pricing.
- increased local or distributed generation/supply options, including:
  - capacity for standby power from existing or new embedded generators
  - using energy storage systems, load transfer capacity and more."

Three separate RIT-D reports must be prepared and made available to stakeholders[38] according to the flow chart in Figure 35. The Non-network Options Report should be available for 3 months to allow stakeholders to have input. Such input can include the identification of options not included in the Non-network Options Report that could be used to meet the network need. A Non-network Options Report does not need to be prepared if the DNSP determines, on reasonable grounds, that no non-network options could be potential credible options or form a significant part of a credible option.

A Draft Proposal Assessment Report (DPAR) must be made available to stakeholders for comment for at least 6 weeks and should include such details as:

1. A description of the identified need for the investment
2. The assumptions used in identifying the identified need
3. If applicable, a summary of, and commentary on, the submissions on the Non-network Options Report
4. A description of each credible option assessed
5. Where a DNSP had quantified market benefits, a quantification of each applicable market
6. Benefit of each credible option where applicable
7. A detailed description of the methodologies used in quantifying each class of cost or market benefit
8. The results of a net present value analysis of each credible option and accompanying explanatory statements regarding the results
9. The proposed preferred option and details on its technical characteristics, estimated construction timetable and commissioning date (where relevant)
10. Indicative capital and operating costs (where relevant)

[38] Stakeholders include Registered participants, AEMO, Interested parties and Non-network providers, and if the proponent is a DNSP, then stakeholders include persons registered on its demand-side register.

A Final Project Assessment Report is then prepared and made available to stakeholders, and must include a summary of any submissions received on the DPAR and the response to each submission.

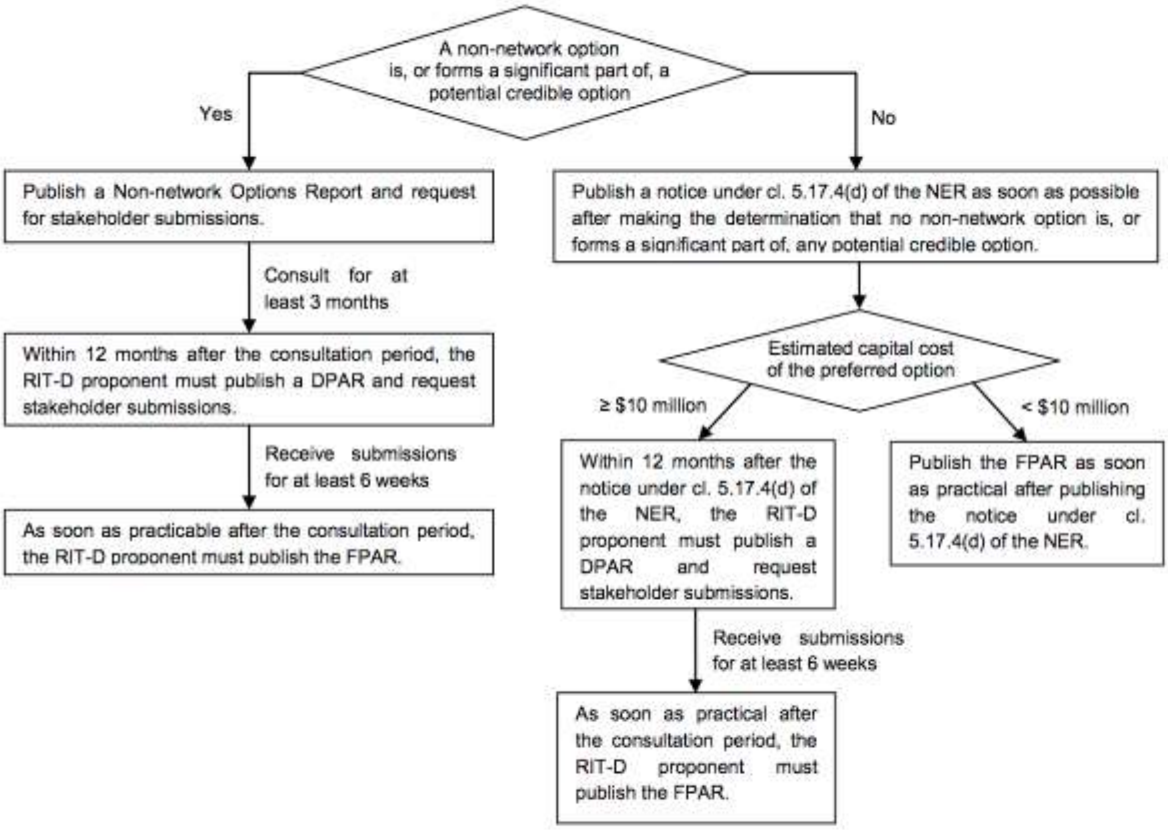


Figure 35 Flow chart of the RIT-D process that includes a non-network option (AER, 2013c)

The RIT-D assessment must include modelling of reasonable scenarios that vary the levels of economic and population growth and associated electricity demand, capital and operating costs, environmental penalties and the value of unserved energy. Sensitivity analysis of relevant parameters that allow for uncertainty and risk must also be conducted. The modelling period should be long enough for the benefits of high-cost investments to be realised. If, after the FPAR has been completed, there is a material change in circumstances which means that the identified preferred option is no longer the preferred option, the RIT-D process must be re-applied.

There are a number of circumstances where RIT-D does not apply:

1. Where there is an urgent and unforeseen network issue
2. Where the project will cost less than $5 million
3. Where either the project can be funded through charges that don't relate to standard control services or where the asset provides services other than standard control services
4. Where the project is related only to the refurbishment or replacement of existing assets (not augmentation)

8.4.1. Assessing RIT-D as an IRP process

The RIT-D is certainly an improvement over existing processes and is a step in the right direction. It has a clearly stated aim and formalises the inclusion of non-network stakeholders, who are able to propose their own non-network options. It has a well-defined process that lists the minimum non-network options that must be considered, and requires a stand-alone Non-network Options Report. The requirements of the DPAR are well defined, it must include all assumptions and the methodology used, and must conduct scenario and sensitivity analyses. It is open to scrutiny by all stakeholders, and is reviewed by an independent body, the AER.

However, currently the RIT-D does not need to be applied where the project is related only to the refurbishment or replacement of existing assets. This is because on page 95 of the AEMC's 14 June 2012 draft decision, it states:

> "It is appropriate to exempt these projects from the scope of the RIT-D on the basis that the benefits to be gained from their assessment under the RIT-D would, in most cases, be unlikely to outweigh the costs, risks or regulatory burden on relevant NSPs from applying the RIT-D process."

Because rule 5.17.3(5) (NER) explicitly exempts refurbishment or replacement projects, the AER has no authority to request that the RIT-D application guidelines apply to this type of project. However, application of the 'greater than $5 million' rule should exclude projects where the costs outweigh the benefits – at least as well as it does for network augmentations. In such cases, if non-network alternatives are shown to have a greater net economic benefit over the projection period, the size/cost of the network could be reduced, which could result in absolute cost reductions. Exclusion of refurbishment or replacement projects from RIT-D also provides an incentive for augmentation projects to be misclassified in order to avoid the RIT-D requirements.

There appears to be no process to encourage the effectiveness of non-network solutions to be tested in advance. Incorporating significant levels of non-network options into network planning processes is likely to be very challenging for most DNSPs, which are network specialists and are unlikely to have expertise in all the various DE options possible. There will also be an entirely justified level of uncertainty regarding the degree to which some non-network options can be regarded as 'firm capacity'. Combined, these will result in an inherent conservatism against unfamiliar non-network options. Thus, there should be some process whereby DNSPs are encouraged to implement non-network options before they are needed, so their effectiveness can be assessed in advance.

The RIT-D process includes only economic impacts. The inclusion of externalities such as the minimisation of environmental impacts, reduced risk during extreme weather events, increased electrification of disadvantaged areas, local employment and capacity building, could broaden the beneficial impacts to society as a whole.

The limit for eligible projects is $5 million, which means that many smaller opportunities for DE will not be subject to the planning process. Whether or not these can adequately be accommodated via day-to-day 3rd party competition, discussed in the next section, will need to be tested.

With the RIT-D becoming operational on the 1 Jan 2014, it will be interesting to see what effect it has on the coming Network Determinations.[39] The Stage 1 Framework and Approach paper for the NSW and ACT DNSPs has already been released, although there is a transitionary period that finishes on 30 June 2015, with the subsequent period extending out to 30 June 2019, and so it is reasonable to expect the RIT-D to have an impact during this later period. Qld's and SA's next regulatory periods

[39] The expected effect being a reduction in the revenue cap below what it otherwise would have been. Being counterfactual, this will be difficult to assess.

start on the 1 July 2015, Victoria's on 1 Jan 2016 and Tasmania's on 1 July 2017, with all their Framework and Approach papers released after the RIT-D was incorporated into the NER. Thus, all these jurisdictions' Network Determinations should be affected by the RIT-D.

All the Network Determinations are for five years, and so combined with regulation under a revenue cap (as discussed in Section 9.1.1), there is a clear incentive for DNSPs to embrace RIT-D and so implement alternatives to network augmentation where they are cheaper. Of course, if demand peaks do continue to decline, over the five-year Determination period there is a clear risk of excessive profits for DNSPs.

9. Full Competition on a Day to Day Basis

The market arrangements required to drive full competition between all supply and demand-side options on a day-to-day basis can be divided into three types:

4. Those related to the operation of the incumbents;
5. Those related to the design and operation of the distributed energy market itself; and
6. Those that then stimulate the broader distributed energy market and enhance the interaction and operation of all participants.

The following examples are not meant to be exhaustive but are used to illustrate the measures that may be possible under each of the above types. They also focus on regulatory arrangements, especially the structural characteristics, rather than on the more technical aspects of a DE market. A number of reports have more comprehensively listed the various barriers and policy options to address them – for example Dunstan et al. (2011).

9.1. Operation of incumbents

The market arrangements related to the operation of the incumbents can be subdivided into those that decrease utility opposition to distributed energy and those that enable utility participation in distributed energy.

The most critical example of the former is the decoupling of DNSP revenue from electricity sales, which here we propose involves network operators being regulated under a revenue cap rather than a Weighted Average Price Cap (WAPC)[40] – see Section 9.1.1. An example of the latter would be retailers acting as energy service providers and so providing EE options to reduce energy use (as can occur under some White Certificate Schemes). Another possible example of the latter is the recommendation of the PoC Final Report that network operators be allowed to own and operate DG – however, as discussed in Section 9.1.2, this could have anti-competitive impacts if DNSPs' regulated revenue provides them with an unfair advantage over 3rd party providers.

9.1.1. Decoupling DNSP Revenue from Electricity Sales

Where network businesses are regulated under a WAPC, they are exposed to 'volume risk', meaning that if the weighted average of total sales is greater than was forecast in the network determination, their revenue will be more than expected, and possibly vice versa. Thus, as stated in the PoC Final Report, having DNSP revenue coupled to electricity sales in this way "can result in an incentive to increase consumption above the forecast approved in the regulatory determination and a preference to prevent projects that lead to decreased volumes" (AEMC, 2012, page 215).

Methods to decouple revenue from sales can be divided into two types: those that focus on decoupling revenue in general (through revenue cap regulation, as discussed below) and those that focus only on revenue loss due to particular DE activities (York and Kushler, 2011).

In the PoC Final Report, the AEMC looked at both types of options. The only option they recommended was of the second type: selective compensation of network operators for foregone profits resulting from particular DSP programs. A form of this option, Part B of the Demand

[40] Under the WAPC approach, a network operator's volume-weighted price revenue can increase from one year to the next, so as total volumes increase, total revenue can also increase, and vice versa. The WAPC can be altered in the next Determination period (discussed below), which is typically 5 years.

Management and Embedded Generation Connection Incentive Scheme (DMEGCIS), is currently in operation but is considered by the PoC Review to be ineffective.[41] The AEMC's Draft Report discussed two improvements that highlight the difficulty in providing a network operator regulated under a WAPC with an incentive to implement DSP projects that still has benefits for consumers (AEMC, 2012a). In one, where a DSP project delivers wider market benefits, the distribution business would earn a share of those benefits – however this would apply only to projects that deliver such benefits, which may be too small to justify implementation. In the other, the distribution business would retain the capex[42] savings due to deferral of capital investment for long enough to justify that investment (based on a regulated rate of return), with all future savings going to consumers. In this case, the only benefits delivered to consumers would be those in excess of what is required to justify implementation. In addition, this type of case-by-case compensation is not suitable for DSP independently sourced and implemented by consumers or by 3rd parties, and so has limited effectiveness for a wider distributed energy market. Other criticisms of this type of compensation include: it is an asymmetric upward adjustment in rates that protects the DNSP from sales decreases due to reduced electricity use, but does not protect customers from increased collection of revenue if sales increase above the forecast; it requires expensive and time-consuming processes to determine energy program savings; and the process to receive regulatory approval for recovery of "lost revenues" can be contentious (York and Kushler, 2011).

Another option in the PoC Final Report was to have high fixed daily connection charges, however this was not discussed, presumably because it would reduce the financial viability of both DG and EE if combined with lower usage charges, and so would be in conflict with Recommendation 16 of the Report: "Amend the NER [43]distribution pricing principles to provide better guidance for setting efficient and flexible network price structures that support DSP" (AEMC, 2012, page iii). Nevertheless, as discussed in Section 5.1, this is already occurring in Australia and it has even been proposed that owners of PV systems should have to pay higher fixed charges than customers without PV.

Another option involved establishing a "comprehensive DSP incentive mechanism, which, while not expressly designed to recover lost revenues, can nonetheless mitigate financial attrition and remove disincentives if well designed" (AEMC, 2012, page 217). This does not appear to be further discussed in the Report but is similar to one of the proposals in the Executive Summary: "Building a framework that will provide a commercially sound and sustainable basis for making DSP part of the network planning and investment process" (AEMC, 2012, page iv). Although this also does not appear to be further discussed, it very nicely describes the IRP and RIT-D discussed in Section 8.

Revenue cap regulation

The AEMC PoC Report also discussed the use of revenue cap regulation instead of a WAPC. Under such regulation, if sales are less than expected, tariffs can be increased in the following year to compensate. The AEMC rejected a revenue cap on the basis that it would reduce the incentive to set cost-reflective tariffs, and would provide an incentive to maximise profit by decreasing expenditure. However, it is unclear why a revenue cap would reduce the incentive to set cost-reflective tariffs since such tariffs should decrease the need for network expenditure and so increase the network operator's profits. Similarly, network operators are currently subject to strict

[41] DMEGCIS is intended to provide incentives to DNSPs to implement efficient non-network alternatives, to manage the expected demand for standard control services or to efficiently connect embedded generators. Until recently it was called the Demand Management Incentive Scheme (DMIS).

[42] Capital expenditure

[43] National Electricity Rules

regulations regarding the availability of networks to provide both power quality and reliability of supply, which should be adequate to ensure sufficient expenditure.

Revenue cap regulation is essentially one of the types of decoupling used in the United States (RAP, 2011), and in Denmark (since 2000), Germany (since 2009), the UK (since 1990) and Spain (Ropenus et al., 2011), and in fact already applies to the DNSPs Energex and Ergon in Queensland, as well as to transmission network operators Australia-wide (AEMC, 2012). It has been proposed for DNSPs in Australia as far back as 2008 (ISFRAP, 2008), and during the course of this project, in March 2013, the AER announced that it would apply to the next network determinations that are due for assessment - both the ACT and NSW. In Australia, the revenue cap may be on a CPI-X basis, meaning, in this case, that the revenue cap must be adjusted each year for inflation (according to the Consumer Price Index) and reduced by any expected efficiency savings[44] (AER, 2013d; 2013e). Most recently, the Productivity Commission has also changed its view, and now supports revenue caps over WAPCs (PC, 2013).

The ACT and NSW revenue caps will be applied to all standard control services,[45] and, like the revenue cap applied to TNSPs, will include an 'overs and unders' (O&U) process. The O&U process essentially means that any over (or under) recovery of network costs in a given year must be paid back (or recovered) in the following year (including interest impacts) by adjusting the following year's maximum allowable revenue (MAR).[46] The AER provides a detailed explanation for why it now prefers a revenue cap over a WAPC, but the main reasons are that a revenue cap provides better individual tariff price stability, more efficient cost recovery and better incentives for demand side management. The AER considers that not only does revenue cap regulation remove the disincentive for DNSPs to allow DSM, it also provides an incentive - because DNSPs can increase profits by reducing costs, which creates an incentive for activities that reduce the need for network augmentation (AER, 2013d).

Thus, under a revenue cap with O&U, a DNSP:

(i) avoids lost revenue due to reduced sales,

(ii) can recover the cost of any DE it undertakes (assuming that it only undertakes DE because it is cheaper than the cost of augmentation, the cost of which is covered by the Determination process), and

(iii) can retain the net capital and operating cost savings for the remainder of the regulatory period.

9.1.2. Ownership and Operation of DE by Network Operators

Australian networks are regulated monopolies, and their participation in other competitive elements of the electricity supply chain may result in uncompetitive behaviour, such as (AER, 2011, p5):

- "limiting access of competitors to the distribution network by delaying or degrading connections ,

[44] Performance targets or efficiency incentives are typically included to encourage the reduction of energy demand through improved efficiency of infrastructure and the use of demand side management (C2ES, 2013).

[45] Standard control services are those distribution services that are central to electricity supply and therefore relied on by most (if not all) customers. Most distribution services are classified as standard control, reflecting the integrated nature of an electricity distribution system. Standard control services include network services, most network augmentations and, in limited circumstances, network extensions. These services encompass construction, maintenance and repair of the network for existing and new customers (AER, 2013f).

[46] According to Clause 6.18.2(b)(6) of the National Electricity Rules.

- restricting the quantity and quality of the distribution service provided to competitors or improving the network performance for its affiliated interests,
- sharing commercially sensitive information regarding competitors with its affiliated interests,
- the way it negotiates and processes connection arrangements with competitors as opposed to affiliated interests, and
- shifting costs between the regulated and unregulated activities."

This has significant implications for DE that is deployed by 3rd parties, and is a particular focus of the AEMC PoC Review, amongst others (AEMC, 2012). The above points can be separated into two different types of uncompetitive behaviour:

(i) where the DNSP restricts the network access of 3rd parties competing directly with its network business, and

(ii) where a DNSP uses the regulated revenue to gain a competitive advantage over 3rd parties that operate in a competitive market and compete with its network business.

The Distribution Ring-Fencing Guidelines (DRFGs) developed under the National Electricity Rules can include provisions dealing with legal separation, accounting separation, allocation of costs, limits on the flow of information, and waiver of obligations under the guidelines. They aim to limit "the ability of vertically integrated DNSPs to use their market power and favour related businesses to the detriment of an efficient market" (AER, 2011, p6). Thus, they focus only on the second type of uncompetitive behaviour. Further, the DRFGs only "help limit the ability of vertically integrated DNSPs to discriminate against upstream and downstream competitors" (AER, 2011, p6), they don't completely stop any such discrimination.

The RIT-D process described in Section 8.4 should help address the first type of uncompetitive behaviour during network planning processes, because supply side (network augmentation) and demand side measures are assessed through a transparent process overseen by an independent body. Similarly, it should help address the second type of uncompetitive behaviour, especially if combined with the DRFGs. However, for DE deployed on a day-to-day basis, additional measures are required to address the first type of uncompetitive behaviour, and some examples of such measures are discussed in Sections 9.2 and 9.3 below, as well as elsewhere (for example, Dunstan et al., 2011).

The situation is further complicated if a DNSP, or an associated business, wishes to participate directly in the DE market. In this case, variations of both types of uncompetitive behaviour defined above could occur:

(i) where the DNSP restricts the network access of 3rd parties competing directly with its *DE business*, and

(ii) where a DNSP uses the regulated revenue to gain a competitive advantage over 3rd parties that operate in a competitive market and compete with its *DE business*.

Again, in this situation, the DRFGs will help address the second type of uncompetitive behaviour, and the RIT-D process described in Section 8.4 should help address the first and second types of uncompetitive behaviour during each regulatory period, especially if combined with the DRFGs, but would be insufficient for the first type of uncompetitive behaviour for DE deployed on a day-to-day basis.

One compromise that has been suggested by OG (2012) is that DNSPs could own DE assets that would then be made available to 3rd parties (retailers/aggregators etc) to operate on a competitive basis. This would mean that competition would be introduced both when hardware was purchased and during operation. However, DE options would be limited to those selected by the DNSP, and such options could have an unfair advantage over alternatives selected by 3rd parties.

As discussed in Section 5.1, DNSPs currently receive regulated financial support for DSM through DMIS/DMEGCIS, and Energex has received approval for a 5 year DSM plan in its most recent regulatory proposal, which not only covers the expected costs but allows Energex to secure a portion of the projected long-term and upstream benefits for itself. Such financial support could be said to provide the DNSPs with an unfair advantage against 3rd party DSM suppliers, however it may also simply enable DSM that would otherwise not have gone ahead. In this regard, 3rd parties may never have an opportunity to provide services, if the need is identified internally by the DNSP. While an assessment of any anti-competitive impacts of these particular support mechanisms is beyond the scope of this project, they do serve to highlight the potential for DNSP participation in DE to have anti-competitive impacts in the current regulatory environment.

It is worth noting that the financial ring fencing discussed above really needs to be only 'one-way', in that there is no reason that money should not flow to the regulated monopoly from an associated DE business.[47] Where the DNSP is regulated under a revenue cap, any profits from the associated DE business that are returned to the DNSP would place downward pressure on tariffs (because the DNSP can't keep the additional income). Of course, some incentive would be needed for the DE-arm to feed it's profits back to the DNSP. In addition to the taxation benefits to the DE arm, one option could be for a percentage of these profits to not be counted towards the DNSP's revenue, meaning they would be allowed to keep them. This could potentially be combined with some allowance for a percentage of the DE costs to be counted by the DNSP as either opex (and so increase their expenditure) or capex (and so increase their regulated asset base), depending on which was most advantageous to them.[48] However, such proposals at this stage are speculative and would need to be subject to detailed investigation.

9.2. Design and operation of the distributed energy market

Measures related to the design and operation of the distributed energy market itself focus on establishing an environment where different participants can compete fairly, including new entrant 3rd parties.[49] Again, the following examples are used for illustrative purposes and focus more on market structure than on technical aspects.

(vi) That consumers be able to source their electricity from, and sell their DSP to, entities other than their retailer (portability) (AEMC, 2012a),

(vii) That a new category of market participant for non-energy services be introduced in the National Electricity Rules to unbundle the sale and supply of electricity from non-energy services, such as ancillary services (AEMC, 2012a),

[47] One way ring fencing is used in petroleum resource rent taxes, for example the North Sea Taxation System where losses from oil and gas production activities can be offset against income external to these activities but not vice versa (HWU, 2009), as well as for various UK government departments depreciation budgets eg. https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/77769/Pomeroy_GC.pdf and http://www.visitbritain.org/Images/DCMS%20Funding%20Letter_tcm29-28682.pdf

[48] Expenditure under DMIS/DMEGCIS can be claimed as either capex or opex, and of the 22 projects registered for 2011/12, 1 was claimed as capex, 3 were opex and capex and 18 were opex (AER, 2013d). Discussions of possible reasons for favouring either capex or opex are discussed in York and Kushler (2011) and in AEMC (2012).

[49] Interestingly, in Europe, a direct relationship has been found between market diversity (the number of 'suppliers' in the electricity market), and the level of deployment of DG ie. the more suppliers the more DG (Ferreira et al., 2011))

(viii) That third parties (non-retailers and non-regulated network services) be able to provide energy services to residential and small business consumers (AEMC, 2012a),

(ix) The formalisation of solar access rights, which is important not only for solar-based DG, especially PV, but also for EE technologies such as SWHs and even for lighting and heating passive solar designed buildings (APVA, 2009),

(x) Simplify and streamline the process for connection of DG to the network,

(xi) Price signals that better reflect the cost of supplying electricity at specific times. While this would not necessarily benefit PV on residential networks (although it could influence load patterns), it would provide a useful price signal for distributed storage and DSM, as well as PV on commercial networks. This should include DUOS charges for DG that better reflect their use of the network.

9.3. Stimulation of the distributed energy market

Measures that can stimulate the distributed energy market are all those that, once the market has been established, enhance the operation of all participants (both incumbents and new) and so drive the uptake of distributed energy technologies. Policy measures to promote distributed energy can be broadly categorised into:

4. Support mechanisms such as the provision of information and training. They are typically voluntary and are generally the most widely implemented energy efficiency policy measures to date.
    a. Information on the energy use of appliances, star ratings etc.
    b. Information on conducting energy management plans and energy audits
    c. Better forecasting of both short and long-term demand (AEMC, 2012),
    d. Publications of annual maps of network constraints and opportunities for DSP that could offset network augmentation (EEC, 2011),[50]
    e. Vocational programs that focus on training and skills development
    f. Capacity building in organisations wishing to participate in the RIT-D process (D'Sa, 2005)
5. Command and control mechanisms. Have delivered some of the greatest successes in energy efficiency policy, as measured by their impact on energy use. They can reduce the transaction costs and effort required by individual decision-makers to choose optimal levels of energy use by effectively taking some energy efficiency decisions at the societal level (ie. government makes the decision on society's behalf). This bypasses some of the existing market failures in energy-related decision-making.
    a. Minimum energy performance standards (MEPS)
    b. Building standards (BASIX)
6. Price mechanisms that change the energy 'price' seen by decision-makers for different energy options, such as:
    a. Emissions Trading Schemes and carbon taxes, that increase the cost of energy and so increase the viability of DE options.

[50] For example, see the network constraint maps that can be produced by the Dynamic Avoidable Network Cost Evaluation (DANCE) model (Langham et al., 2011)

b. White certificate schemes such as the state-based schemes and the proposed Energy Savings Initiative (but also including those that target reductions in demand peaks).
c. The demand response mechanism recommended by the PoC Report discussed in Section 5.2 (as well as any like it that reward end users for reducing demand peaks) (AEMC, 2012).

10. Responses by Utilities and Regulators to these Proposals

Customer responses are significantly influenced by the regulatory framework and the tariff structures, metering arrangements and costs that these determine. It was therefore considered important to gauge the views of regulators on electricity sector developments, options for distributed energy, and the specific proposals discussed in the last two chapters. Similarly, the responses of electricity utilities to distributed energy options are largely determined by the regulatory framework under which they operate, so their views on proposed changes are important.

10.1. Process followed for regulator feedback

A set of structured interview questions was developed, along with a short discussion paper outlining the distributed energy market options discussed previously, and State and Australian regulators were contacted. In response to phone and email contacts, discussions were held with the Australian Energy Regulator (AER), the Australian Energy Market Commission (AEMC) and two State regulators. Only two regulators agreed to participate in the full structured interview, although general discussions around the topic were held with others. For those who decided not to participate formally, reasons given included that the AER was now responsible for regulatory determinations; State agencies were responsible for policy settings; lack of time; the need to gain formal approval for any opinions offered; and the preference for options to be canvassed via their own consultative processes, rather than being offered independently.

10.1.1. Issues Discussed

The following provides a summary of responses provided, either through the formal interviews or via general discussion.

Electricity use

There were differing views on the cause of recent declines in electricity use, whether or not they were real and whether they were likely to continue. Reasons given included:

- Mild summers, with an expectation that a return to hot summers would see peak demand increasing again. However, it was noted that last summer was hot and demand still did not increase, pointing to systemic change.
- Manufacturing slowdown
- Increased prices influencing usage
- PV and energy efficiency, although one regulator commented that PV customers may not have reduced actual usage much.

In terms of future expectations, views differed. Some felt that demand has been volatile, expected increases in peaks have not occurred and approved network investments may slow or not be carried out. Others commented that environmental drivers are no longer dominant, implying that, if prices stabilise, demand will grow again.

Electricity tariffs and drivers

The general view was that network investments already made will lead to price rises, but in future these rises should be less than in recent years. New Government obligations, e.g. to accommodate bushfire risk will, however, lead to some further increases.

The take-up of TOU pricing is expected to vary by State, but is generally expected to be slow. The Victorian flexible pricing approach is considered to be a 'soft start' towards more cost-reflective pricing, while the NSW metering rollout is not as 'smart' as in Victoria, so future options are reduced.

Cost/benefit analyses on smart meter rollout in Queensland have been negative, so transition to TOU pricing is unlikely for residential customers in the short term. However, commercial sector uptake may be higher. It was noted that PV customers are the largest residential group with TOU meters, although not all have taken up TOU tariffs.

Current fixed daily network charges in regulated tariffs are considered to be too low and kWh charges too high. It is considered likely that these will be adjusted over the next 3 years.

The PV impact is now obvious, but no other substantial new technology changes are expected. Electric Vehicle uptake is likely to be slow and home Energy Management Systems are not yet fully mature, so their uptake, and hence their impact on demand profiles and tariffs, is not expected to be large in the short term.

Implications of continued decline in electricity use

Generators

Coal generators are already seeing the impacts of distributed energy uptake, with some boilers being turned off. More gas generation is resulting in more system flexibility.

The longer-term response from large fossil fuel generators will depend on carbon price trends, renewables uptake and PV demand side uptake. They may pursue the gentailer model to cover volatility.

Networks

If demand continues to fall, there will be no new network builds, or delays in currently planned projects. Some replacements will continue as part of normal maintenance. Fixed charges, however, are expected to increase.

Retailers

Retailers are considered to be under a lot of pressure at present, with volatile wholesale markets and rapid changes in margins posing difficulties. There is strong competition for customers, with relatively high churn rates.

Continued demand reduction will see a need to control costs, for instance, reduced door-to-door marketing. On the other hand, low usage customers are considered low risk, being less likely to change retailers, and so retailers are less concerned with reduced demand than with maintaining customers.

There is currently no evidence of new distributed energy offerings or packages to customers, although most retailers offer PV with finance already. PV customers are considered to cost more to service and so may have an extra administration fee added to their bills.

Preferred regulatory responses

The most efficient outcomes will follow informed customer choice. Customers disconnecting from the grid and using stand-alone systems could be one of these choices. However, regulators need to encourage overall long-term efficient use of the electricity system.

The implications of the new Transmission Access review could be significant, including how best to connect new renewables. A level playing field is needed. Solar policy should bear in mind the impacts on those who don't or can't install it.

Batteries

Battery uptake is expected to be slow, with no indication that they are cost-effective yet. The results of Smart Grid trials will be interesting, but commercial uptake of smart grid options are also likely to be slow.

There is no evidence that networks are actively examining storage options for their own use, other than in trial systems. However, proactive companies may be considering batteries. From a regulatory viewpoint, the main interest is in market efficiency - cost effectiveness and equity for all customers.

Comments on suggested approaches to Distributed Energy Markets

The discussion paper circulated to regulators canvassed options for the use of revenue caps, integrated resource planning and ring fencing to allow network operators to participate fairly in new markets. The following summarises comments on each suggestion:

Revenue Caps for Network Operators

A Revenue Cap mechanism has been used in Queensland and is now being extended to other States. It is expected to promote businesses looking at options to network upgrade and also to reduce windfall profits and capex approvals due to previous temptations to understate demand.

Use of shorter determination timeframes may also assist.

Integrated Resource Planning

Various IRP models have been examined, including those proposed by the Institute for Sustainable Futures at UTS. A key issue is deciding the role of government regulation versus letting businesses decide on the best strategy.

An evolutionary process is needed to get from the current to a new regulatory model. The new Regulatory Investment Test for Distribution is an embryonic version of IRP and should see DSM uptake, even if demand increases again.

There is a need to change organisational culture. Service reliability remains a key issue, and new DE options are not as well understood or trusted.

One-way ring fencing

The current status of network businesses is under consideration. Where distributed energy, including demand management, provides a financial advantage to distributors, this should lead to reduced cost of maintaining the regulated asset base.

Independent players competing with generators, networks and retailers

In principle, the market should be open to anyone.

Shared asset guidelines, including leasing to 3rd parties, could provide customer benefits.

Retailers are already using web portals to give customers more information, and as a marketing tool. Networks may seek to do the same. This will improve customer understanding of their energy use, allow more competition and potentially improve access for 3rd parties.

Stand-alone supply as an option to grid in high risk / high cost grid areas

Stand-alone supply should be an option in high grid-cost areas, which were previously built in line with Government policy on social development, not cost-effectiveness.

Island networks (mini-grids) have been examined and may evolve as technology improves or becomes more accepted.

Other issues

The AER Better Regulation website provides updated information on new regulatory proposals. New pricing structures and non-pricing options, such as load control, are being considered.

Options such as tri-generation for medium loads may be useful. However, connection issues need to be resolved, including who pays for which aspects. There is an underlying 'right to connect', but issues remain around how best to deal with safety and technical reconfiguration.

In theory, the market needs to be fully contestable, but the whole process needs to be reformed before that can happen. Flexible tariffs are likely in future. PV has been a catalyst for change.

Tension between parties and split incentives are issues under disaggregated market structures. Regulatory frameworks need to ensure the most efficient outcome, especially when externalities are difficult to capture.

Electric vehicles would most likely change the system peak to later in the evening, which would impact networks and prices. The impacts will depend on what tariff structures are available and how long each vehicle needs to be charged.

10.1.2. Summary

The responses from regulators illustrate a number of points:

Regulators have responsibility for the electricity grid and associated market operation. They do not have jurisdiction over 3rd parties or other energy supply options. Hence their focus is to facilitate the efficient operation of the incumbents, not necessarily to consider other ways of delivering energy services, unless this would provide a more efficient way for the existing system to operate. This means that when they consider new options, from TOU metering to distributed energy, the focus is on how it impacts on the cost and efficiency of the existing system, not necessarily whether they may provide a more efficient approach overall.

Regulators have established formal processes for consideration of issues or options. These processes are initiated by governments or internal processes, and regulators are not readily able to respond or contribute to processes run by others. Recent processes, including the Power of Choice review and others, have begun to address some of the issues around distributed energy markets, but within the confines of their mandate, as discussed above.

Within the limits of their mandate also, regulators aim for a level playing field and expect all options to be considered on their merit. However, the restrictions under which network operators operate inherently mean that preference is given to maintaining existing structures and institutions, including maintenance of assets which cannot be justified on the basis of cost-effectiveness and providing supply and standardised tariffs regardless of use or cost to other users. New entrants on the other hand need to overcome significant hurdles to enter the market, including proving that they do not add cost for other users of the system.

The processes of regulatory change are slow, with network determinations only reviewed every 5 years, and other adjustments only made after extensive review. This means that current processes have not been able to adjust to the installation of over 2 GW of distributed PV over the past 5 years, and will likely be lagging changes expected over the next 5 years due to continued uptake of PV, but also batteries, demand management and other new technologies.

In reality, regulatory change can only be made with political agreement. For instance, the roll-out of time of use meters and TOU tariffs has been recommended by regulators in some jurisdictions but not implemented.

10.2. Process followed for Utility Interviews

As part of the research project, APVA conducted interviews with a number of Australian electricity industry participants exploring the significant changes to the current regulatory arrangements. A question set was used to guide the interviews. The interviews were conducted by phone.

Fourteen electricity distributors and retailers were contacted and asked to participate. Ultimately, only five agreed. The lack of response can be put down to a number of issues. Firstly, owing to the fact that many of the organisations are very large, simply finding the right person who was able to speak knowledgably about the range of issues was difficult.

Secondly, even when we were able to determine the appropriate person, there was a reluctance to discuss some issues due to the perceived public relations risk, given the high level of attention that the media was placing on electricity costs at the time.

Thirdly, in some cases we were contacting private companies and we assume that there was a perception of minimal commercial benefit from sharing information about their business intentions.

Fourthly, the simple logistics involved in contacting and finding mutually satisfactory times to conduct the interviews proved very challenging due to time constraints. In a number of cases, we failed to elicit any response to our (repeated) requests for an interview. Due to a willingness to participate and relevance to the project, we also interviewed one New Zealand electricity company.

Nonetheless, a number of interesting and informative discussions were conducted which we believe are broadly indicative of the views we would have found across a larger sample group.

10.2.1. Summary of findings

Energy demand and forecasts

Generally, all respondents agreed that demand had softened, although there were mixed views about what was causing this and how long this trend would be sustained. In Western Australia for example, both energy and peak demand are expected to rise substantially in coming years due to significant industrial load from the resource sector.

In NSW however, there was a general sense that demand had fallen primarily as a short-term reaction to price rises and that once the market had become accustomed to the new price regimes, demand growth would return to previous levels; although predicting the likely trends is extraordinarily difficult.

Peak demand was considered the most likely area where growth would occur, with milder weather considered a major contributing factor to recent softened demand.

Although peak demand occurs at a different time in New Zealand (evening heating load) and is less variable seasonally, the same trend of softening energy demand and increasing peak demand is occurring there too.

All respondents agreed that the dynamics at play in measuring and forecasting the changes in demand was extremely complex and difficult to forecast as a result. All Australian respondents noted that PV in particular has had an impact on demand and peak to a lesser degree, but generally that measuring, understanding and forecasting this contribution was very difficult due to a lack of granular data.

A combination of changing demographics and industrial behaviour, rapidly changing price signals and regulations and uncertainty around carbon pricing present a dynamic and unpredictable set of scenarios.

Summary: *Most respondents agreed that while energy and peak demand growth are difficult to predict, they would return to similar previous levels and that the recent softening was a short-term trend.*

Electricity cost and price structures

Most respondents agreed that we have seen a peak in the investment cycle for network spending which has substantially increased prices in recent years, as reflected in Figure 36. Consequently a number of respondents were adamant that from a network and distribution perspective, future increases would most likely be restricted to CPI and not as substantial as has occurred recently.

It was further noted that the Global Financial Crises added to finance costs and that this factor has eased.

Western Australia, and to a lesser degree Queensland, are exceptions to this because of higher than average growth rates and being slightly out of synch with other states in the investment cycle. Further, those states had not passed on electricity price increases in recent years at the same level as other states due to political mandates. Thus it is expected that those states may continue to see more substantial (ie. 10% or greater) increases in the next few years. This is reflected in the recent regulatory allowances for higher than average increases in those states (around 15% in Western Australia and 20% in Queensland) and lower increases in NSW (around 5%).

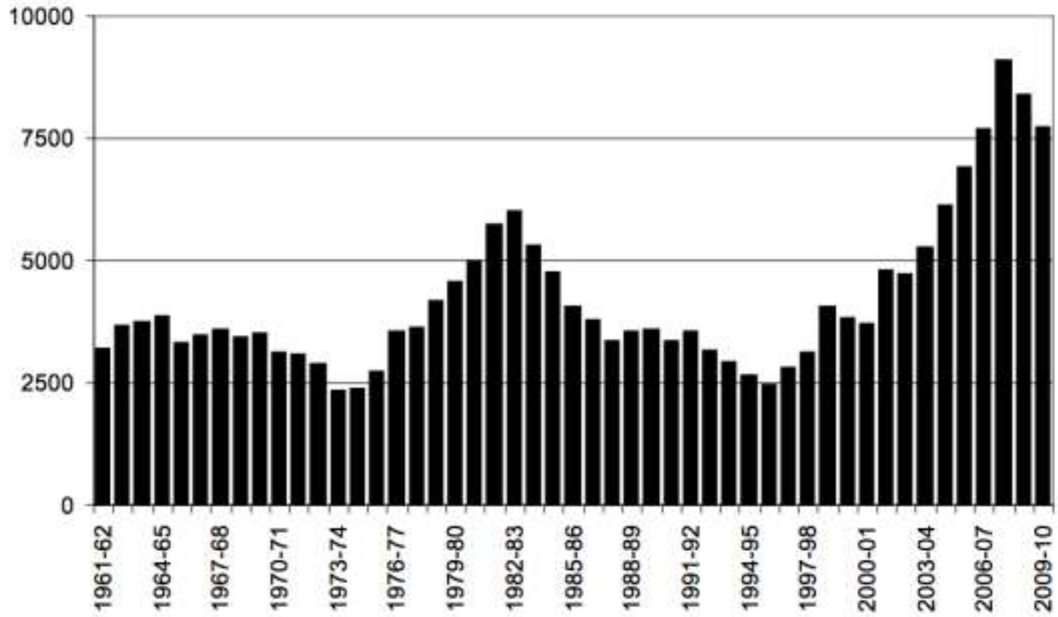


Figure 36 Electricity Supply: Real capital investment ($ million), 1961-62 to 2009-10, constant 2006-07 dollars (SSCEP, 2012)

However, there remain a number of risk factors on the issue of pricing. In particular, the rising cost of gas may result in additional electricity demand growth.

The sovereign risk issue for State budgets was also mentioned because many are experiencing diminished returns from their electricity assets due to falling demand. A major risk factor therefore remains on who prevails in terms of regulatory (price setting) control - politicians or regulatory bodies.

Price structures for electricity are extremely complex and diverse, as demonstrated in numerous recent reports on the topic, and hence, predicting what price rises would be allowed, across various tariff classes, in which states and when, is beyond the scope of this summary. However, all interviewees acknowledged that they were considering different tariff structures and charges which offer some protection from the vagaries of energy demand and provide more predictable returns.

It was noted that different tariff types may not necessarily provide a lasting outcome in terms of behavioural change. Time of Use for example, was seen as a positive for changing consumer demand patterns, but could simply result in higher bills. Consumers need to understand the difference between demand and energy and this can be very challenging. One utility noted for example that despite having a voluntary option for TOU tariffs across their 800,000 customers only 5 had taken up their offer.

One business commented that pricing (re)structure was a big issue and a topic of frequent debate and discussion. They see the de-coupling of pricing from energy through new price structures as very important, not to maintain the existing paradigm, but as a mechanism to pass on transparent costs. Notwithstanding this; there are major challenges to implement it. They do see a future where networks offer a balancing service between demand and supply.

Summary: *The majority of respondents expect a softening of price (rises) in the near to medium term and a return to increases around the level of CPI. They are considering different tariff structures and charges which offer some protection from the vagaries of energy demand and provide more predictable returns. There is a tension between the regulatory conditions which control price setting and the sovereign risk associated with returns for the State-owned entities. Lastly, there are complex human behavioural dynamics at play, which can result in short and/or long-term changes and skewed results.*

Attitudes to regulatory change

As the majority of respondents were Government-owned entities, there was a reluctance and great caution around responses to questions about the merits and impacts of regulatory change. However, a number of salient comments were made.

Most respondents commented that the market needs a much more holistic management of energy policy. Almost all cited the fact that social equity (e.g. community service obligations) forms an element of electricity pricing (as for other utility services such as water and sewerage); many users purchase electricity at or below cost due to their geographic location. This distorts the issue of true cost-reflective pricing and while ever it remains the case, it will mandate a strong political influence in the regulatory process. It was noted that incentives should be used to run networks efficiently but that commercial drivers could & should be in place. Some argued that all utilities should be de-coupled from social equity policy and be purely cost-based to drive increased efficiency.

Almost all respondents were consistent in their comments that regulatory reform was needed to allow for a changing electricity environment but that due to social equity and political drivers, the outcomes of regulatory change were unlikely to reflect an ideal outcome in terms of operational efficiency or the development of long-term pricing evolution.

Some respondents commented that their business operation is dictated by regulation and so unless that changes, the incentives they face won't change. One business commented that they didn't see it as their right, objective or culture to decide what they should or shouldn't be doing with the owner's money; but if the owner says they should do something then they do it.

There were also several respondents who commented that their clear, core function is to simply be effective at running poles and wires business and those resources were increasingly tight. This restricted their ability to spend money or time collecting and analysing data or considering what alternatives exist.

The complexity in investment, cost recovery, behaviour and the energy mix also makes it very difficult to develop effective policies that don't result in unintended consequences. At a National level it is also particularly evident that many differences exist in investment cycles, timing and the growth or decline in demand for electricity. This would (and does) logically require distinct, and in some cases completely disparate, pricing structures and signals across Australia, which is very difficult for consumers to understand.

Generally, all commented that competition (and the potential de-regulation and privatisation) helped and was a good thing, balanced against risk. However, one noted that network operators have and will inevitably learn to monopolise commercial potential (gaming the system) and that government will undoubtedly respond and change the rules over time. How this can be managed and controlled if increased privatisation occurs (given the complexities) remains to be seen.

Summary: *Respondents thought that regulatory reform was needed to allow for a changing electricity environment. However, regulation for electricity utilities is Government controlled and is thus intrinsically linked to much broader political issues than just cost recovery and efficient operation. The majority felt that their roles were primarily restricted to operating their business and broadly advising on the ideal outcomes, but that ultimately political outcomes would determine regulatory conditions.*

Integrated resource planning and other alternatives

Integrated resource planning was discussed with all respondents as an alternative to current cost recovery methodologies. Most were generally familiar with it and felt that they were using some of the elements of this process already.

For example, one commented that they effectively already do IRP by considering the return on investment for customers, including distributed generation and demand forecasts, and then add demand side management impacts. This is then passed through to asset management for analysis.

However, most also commented that this method changed their risk profile and could potentially shift the risk back to DNSP's, and that current demand and price volatility could end up being passed back to customers. Some also noted that their recent price reform submissions were rejected by Government regulators and they were being forced to look at such models, and that in effect they were already operating in a price capped market.

In one case, the business commented that they have no say in what models they can or can't use and that they were simply given a predetermined model by their State regulator and told to comply; irrespective of whether it worked for them or not. They simply had to find a way to build price structures that met the prescribed cost recovery and social equity targets.

One business who owns generation and distribution assets said they already use the integrated resource planning process although they don't use that terminology for it.

One commented that they were currently reviewing their licence conditions with a view to moving from deterministic to probabilistic methods, which they thought would be in line with the concept of Integrated Resource Planning. This business felt that increased investment on (long term) data collection and analysis would allow probabilistic methods to be used with great benefit as they allowed more flexibility and predictive power.

Summary: *Generally, most respondents felt that they already use some (varying) elements of Integrated Resource Planning, although there seemed to be quite different ideas of what it meant. There was concern about increased risk, and in some cases they had very limited power to define what methods they used.*

Distributed energy market opportunities and participation

There was a distinct and clear difference between the views of the government-owned and privately-owned respondents on this issue.

The government-owned businesses were generally consistent with their responses that, with limited exceptions, they were effectively prevented from offering distributed energy or demand side management products and services. The restrictions occur in the fundamental construction of the rules, regulations and licence conditions under which they operate, which are all written with the sale of energy and operation of networks as their scope of work and operational capacity.

One commented that Government is very unclear about what role they want them to play in this space. Treasury has applied very strict criteria around debtor and balance sheets; which makes some projects unacceptable, despite a positive NPV, for example.

One commented that they already are required to provide demand management services; taking offers for demand management submissions today, e.g. like putting in generators. Notably however, their approach was to provide financial incentives to do something until the network upgrade comes into place; their core objective. As such the financial incentives were very limited and had to be balanced against the ultimate cost of providing augmentation.

One example of distributed generation was cited by a network company who provide generators to meet short-term spikes in community demand beyond the capacity of their network. In one part of NSW, portable 500kVa diesel generators are temporarily installed every year and used to meet the Christmas demand peak, for example.

One noted an example where they had been approved for funding to conduct demand management projects and were trying to get more money for broader programs. However, they were trials only and noted that the regulations do allow them to conduct non-network solutions if it really can be demonstrated that it will defer augmentation. This business suggested it could theoretically do whatever it wanted - within the revenue caps – and that this could include broad-based demand management activities. However they have to deliver good or better returns than what they would normally do and there is a significant issue with benefits being delivered over a long timeframe, beyond the regulatory period.

Another cited a similar issue with the returns from demand management programs, noting that innovation takes time to gear up, and that it required a very distinct change in behaviour and a change to the culture. Currently, they have very limited ability to establish such activities due to resource and cost constraints, and the longer timeframes involved in returns.

One business noted that barriers exist around their experience, the time involved in doing the analysis, and cultural differences. They highlighted that philosophically, network company's would always be needed, that is what they historically have been and where they see their expertise. However, they noted that there was an increasing appetite to evolve.

However, one private DNSP we spoke to had a distinctly different perspective, highlighting the issues described above. This business described how they saw a very real opportunity to create new business opportunities in demand management, energy efficiency, solar and energy storage solutions for the network they owned and operated. They suggested they could clearly see future opportunities to monetise the value of load shedding in residential demand, with commercial to follow current trials.

This particular business also owns a metering company, providing an excellent opportunity and understanding of monitoring requirements. This provides outstanding data acquisition and analysis capabilities and allows them to target their activities in cost-effective ways. Currently they are conducting trials on fifty homes with an integrated offer of solar PV, storage, data monitoring, finance and load shedding. Although they are subsidising the current offer to make it affordable, they see this type of solution as logical and inevitable and are very keen to rapidly expand once the data have come in, allowing refinement.

When it comes to offering off-grid PV systems in areas of high risk or where it is more economic than long grid extensions, regulation simply prevents this occurring because their scope is exclusively restricted to business functions connected to the grid. They have and will continue to consider and recommend market-based alternatives where appropriate but generally stay away from this market.

Generally most noted that off-grid PV was either outside their scope and/or such a minority of their customer base that they saw little likelihood of it ever changing.

Summary: *Generally, most respondents felt that they were largely prevented from participating in any meaningful way in demand side management activities by regulatory conditions (although they are involved at the fringes). It was noted by all Government entities that the longer return time frames were an issue and that fundamentally they saw themselves as having a very tight defined scope of work and expertise; which excluded demand side management activities from being anything but a minor activity. Whilst all respondents saw the logic and rapidly increasing cost-effectiveness of many demand side management activities, only the private entities appear willing and able to implement such projects.*

Impacts of storage and PV

All the respondents noted the rapidly decreasing cost of PV and its public popularity. Some Government and private businesses participate in the PV market, although it is generally through “arm’s length” partnerships and generally considered more the domain of retail offers than network operators. Without exception they saw the proliferation of PV as increasingly inevitable but that, due to costs, storage was still some years away from being anything other than a small niche.

However, few recognised any real benefits for networks coming from the deployment of PV in terms of deferred investment due to the very long planning, investment and deployment cycles in network construction. The fact that it is deployed at the whim of customer demand rather than network planning needs has exacerbated this and is creating technical problems in an increasing number of cases. Fundamentally, it is also eroding their revenue streams through lost DUOS and TUOS charges creating challenges for margins and returns.

In line with the comments we received on demand management more broadly, the majority cited a lack of ability to gain financial returns from PV or storage, except in the case of privately owned entities.

Summary: *Generally, most respondents were restricted in their ability to gain any reward from the deployment of PV or storage but agreed that increased uptake was highly likely. As a result, they were facing erosion of their profits, increased cost and increased technical issues.*

11. Discussion

It is highly likely that electricity costs will continue to increase over the medium to longer term,[51] the prices of DE technologies will continuee to decrease, the uptake of DE technologies will continue, and there will be downward pressure on residential (and commercial) electricity demand from the grid. Any declines in demand will put further pressure on utilities' revenue. To date, responses by utilities are entirely understandable given their regulatory environment, and essentially seek to maintain their current business models. Several utilities are interested in DE options but are not well placed to embrace change, due to their expertise base and their regulatory framework. Although governments are now responding to the high electricity prices and the need to increase access to DE, their responses are unlikely to be sufficient and are generally tardy in their implementation (PC, 2013).

As discussed, DE technologies are disruptive and so require transformative rather than incremental changes. Rather than retaining the existing market with DG, EE and DSM integrated on a piecemeal basis, a fully integrated distributed energy market may need to be developed. Because of the continued uptake of DE, such changes are needed to not only optimise DE's contribution to least-cost energy services, but to enable the existing electricity industry to adapt their business models and so transition to the 'new normal'.

Here we propose that the fundamental principle of such a distributed energy market is that of equal competition between supply-side and demand-side options at all levels: generation, networks and retail. Such competition needs to occur on a day-to-day basis, and for networks, needs to be applied more rigorously during the planning stages. Competition between supply and demand side options can be introduced into network planning processes using Integrated Resource Planning (IRP), for example the proposed RIT-D process. A useful framework for categorising the market arrangements required on a day-to-day basis is to separate them into (i) those related to the operation of the incumbents; (ii) those related to the design and operation of the distributed energy market itself; and (iii) those that then stimulate the broader distributed energy market and enhance the interaction and operation of all participants. Policies that focus predominantly on type (iii), as has been the case until very recently, will be insufficient to drive significant uptake of DE.

The introduction of the RIT-D into the network planning processes should help to minimise increases to network peaks because it would draw on a broader range of options and should include competition from third parties. This process should also be more accurate in forecasting network costs and so the network operators' regulated revenue cap is likely to be more accurate. However, as discussed in Section 8.4.1, the RIT-D should not be restricted to network augmentations, but should be applied also to the refurbishment or replacement of existing assets; appropriate processes should be implemented whereby DNSPs are encouraged to test the effectiveness of non-network options in advance; the RIT-D could be broadened to include social and environmental externalities; and if the effects of the RIT-D are not apparent in the DNSPs' planning processes, especially the coming Network Determinations, the AER should make changes to increase its effectiveness.

Of course, for both utilities and regulators, there are certainly costs to more inclusive and transparent network planning processes. However, according to Neme and Sedano (2012, p21) when assessing IRP in the US, "Feedback from several jurisdictions, however, suggests that the process evolves – as it is tested and refined – to one in which the burden on the utility is not only

[51] Possibly not in the shorter term if the carbon price is either removed or converted to a floating price.

manageable but also much more than offset by cost savings. Once that point is reached and utilities are meeting a high standard in their work, the burden on regulators should be quite modest."

As recommended by the AER and the Productivity Commission, to decouple network operators' revenue from electricity use, they should be regulated under a revenue cap. This is already applied to TNSPs in Australia, as well as to Energex and Ergon in Qld, and will be applied to the DNSPs in NSW and the ACT. A revenue cap with Overs & Unders (O&U) would provide network operators with an incentive to allow third parties to implement DG, EE and DSM. Any losses in reduced sales would be compensated in the O&U process, and savings in avoided network augmentation would be captured by the network operator. In the event that DE is reducing network peaks more than expected, there needs to be some effective process in place to avoid network operators capturing too much profit, and to ensure that savings are passed on to customers as much as possible. Note that savings from offsetting energy use and the associated retailer margin would still accrue to the customer.

A number of issues are yet to be addressed to ensure DNSPs don't restrict the operations of 3rd party DE providers. This is particularly the case where DNSPs operate in the DE market, as can currently occur for all DNSPs through DMIS/DMEGCIS, and occurs for Energex in its most recent regulatory agreement. The use of a one-way ring fence may encourage DNSPs to operate in the DE market, if it is structured to allow the network arm to retain some of the profits.

This report started by highlighting an emerging problem, which is the need to pay for networks in the face of decreasing demand. The majority of the charges used to pay for the networks are based on electricity use, rather than demand, and so people who are most responsible for the size of the network (those who cause the demand peaks, such as owners of large air conditioning systems), are subsidised by those who aren't (PC, 2013). Similarly, people who reduce their electricity use (through PV, SWHs, EE etc), will reduce their payments for the grid thereby increasing the grid costs faced by others.[52]

However, both RIT-D and day-to-day implementation of DE could not only reduce the rate of peak demand growth but, if appropriately designed, could also result in absolute reductions in peak demand. This in turn could result in absolute reductions in network costs – by reducing the capacity of the network at times of capital replacement. In addition, although there seems to be a general assumption that increased penetration of DG will result in more complex electricity flows and therefore higher costs, it is worth noting that as the penetration of distributed storage increases, electricity flows are in fact likely to become less complex than they are now. This is because in areas where residential PV owners in the average urban suburb store their PV-electricity instead of exporting it, electricity flow will once again become more unidirectional – from the centralised generators to consumers. Such consumers are unlikely to have sufficient roof space to supply their entire electricity needs, and the stored electricity will most likely be used to reduce peaks in demand, further placing downward pressure on network costs. The increased complexity associated with 'smart grids' will most likely occur behind the meter and so will be paid by individual customers, rather than adding to overall network costs. Further, allowing network operators to participate directly in the DE market, with appropriate safeguards such as one-way ring fencing, could help them diversify their business models, reducing their dependence on network tariffs, and again placing downward pressure on network costs.

Thus, over the longer term, it is possible that a proportion of the fixed component of network costs could be paid through a fixed daily charged based on a customer's monthly demand peak, as already occurs for commercial and industrial customers. In this way, each customer's contribution to

[52] Note that consumers who don't own their own homes or live in flats can still implement a range of EE options, and will soon be able to invest in community-PV systems.

network costs would be related more to their actual contribution to the size of the network. The fixed and variable tariffs should be designed to ensure that the various DE options are supported through their ability to both reduce energy use and peaks in demand. This approach is preferable to the current DNSP suggestions of higher fixed charges for all customers, or specifically for PV customers, which would disenfranchise low energy users, disadvantage low income households (by limiting their ability to reduce costs) and also make price signals less cost-reflective.

A fully competitive distributed energy market, as discussed here, is something that would develop over time, however the required institutional and organisational changes need to begin now and will need to accommodate both the incumbents and new entrants, on an ongoing basis. In the longer term, rather than having a separate 'distributed energy market' operating alongside the existing NEM, it could be desirable for the NEM itself to operate as a single energy market for centralised and decentralised energy supply and demand.

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