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).

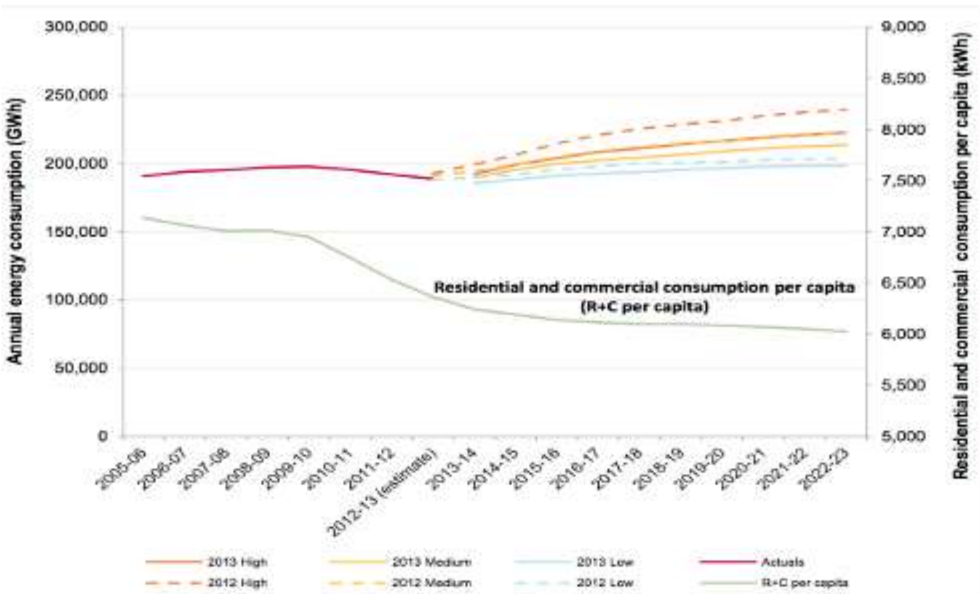


Figure 1. Comparison of annual energy forecasts made in 2012 and 2013 for the NEM under three growth scenarios (AEMO, 2013)

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.

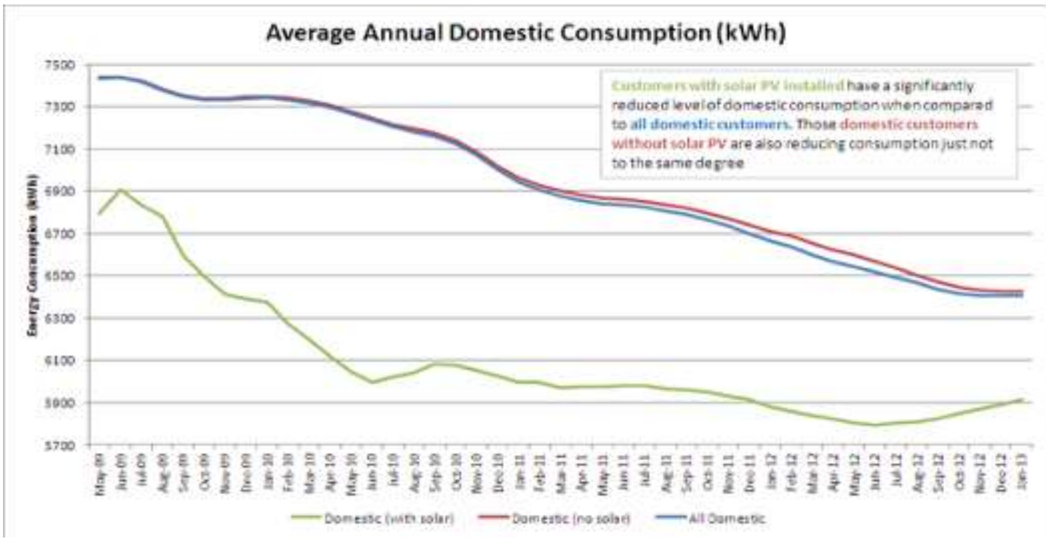


Figure 2 Energex residential demand with and without PV (RE, 2013)

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

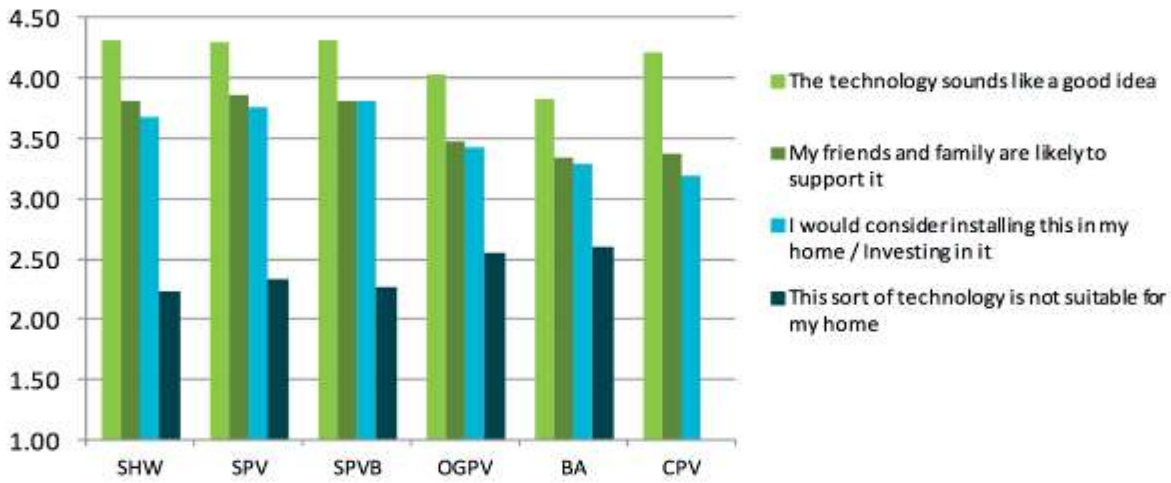


Figure 3 Australian household acceptance of DE technologies (respondents not already owning these technologies)

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.

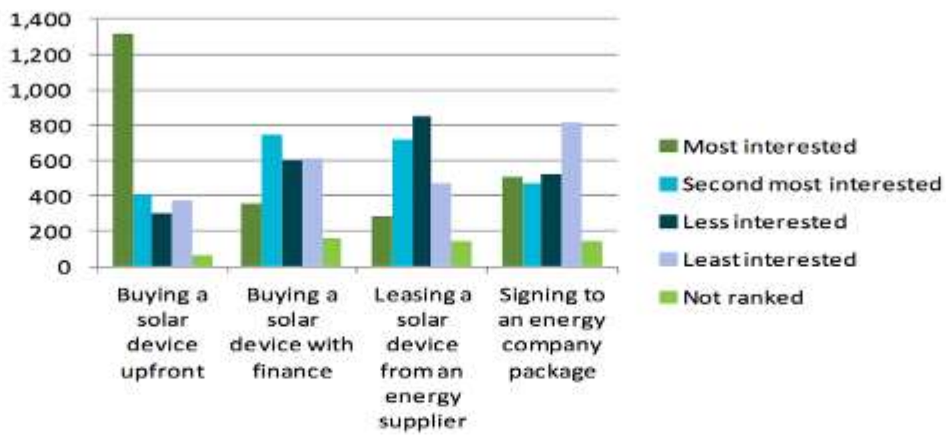


Figure 4 Australian household ranking of finance options to install or replace one of the technology options

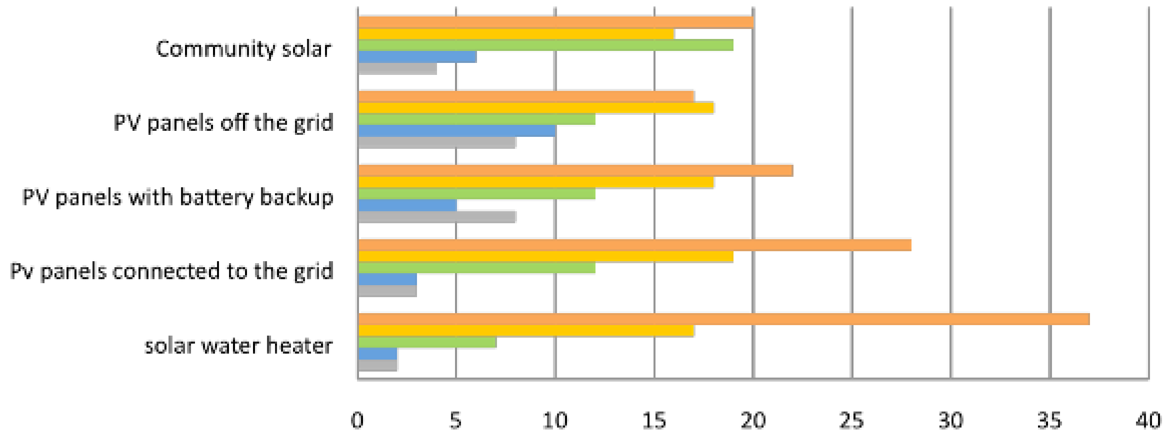
With respondents' being more interested in grid-connected PV with batteries than in batteries alone, it is likely that PV will drive the uptake of batteries. This would in turn enable the installation of larger PV systems and so further reduce electricity demand.

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 ($P<0.05$).

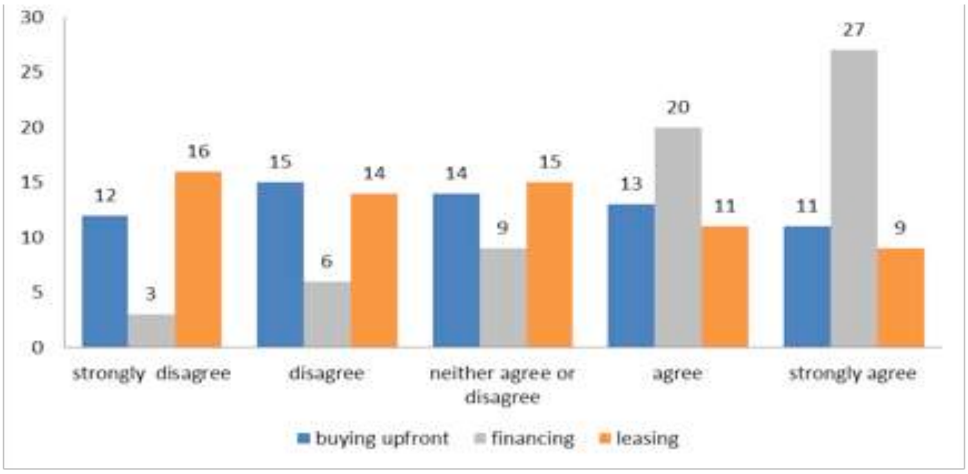


Figure 16. Purchasing preferences

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.

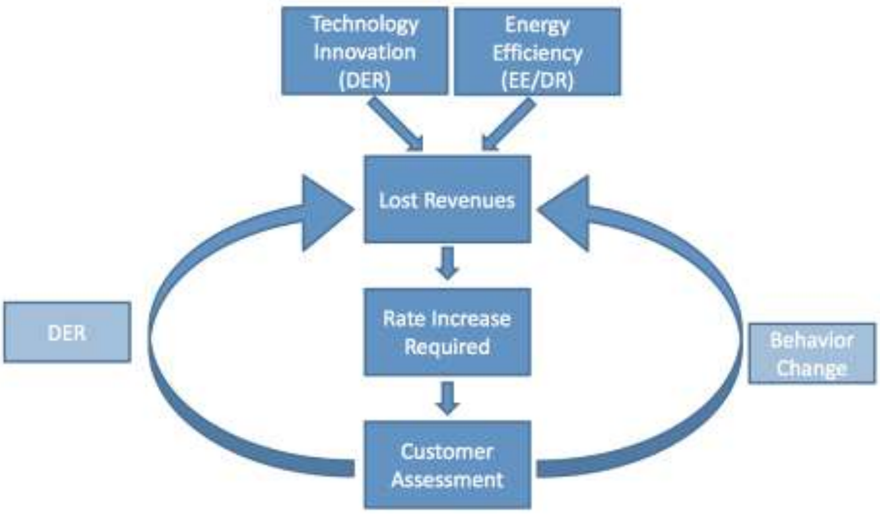


Figure 7. Vicious Cycle from Disruptive Forces (Kind, 2013)

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.

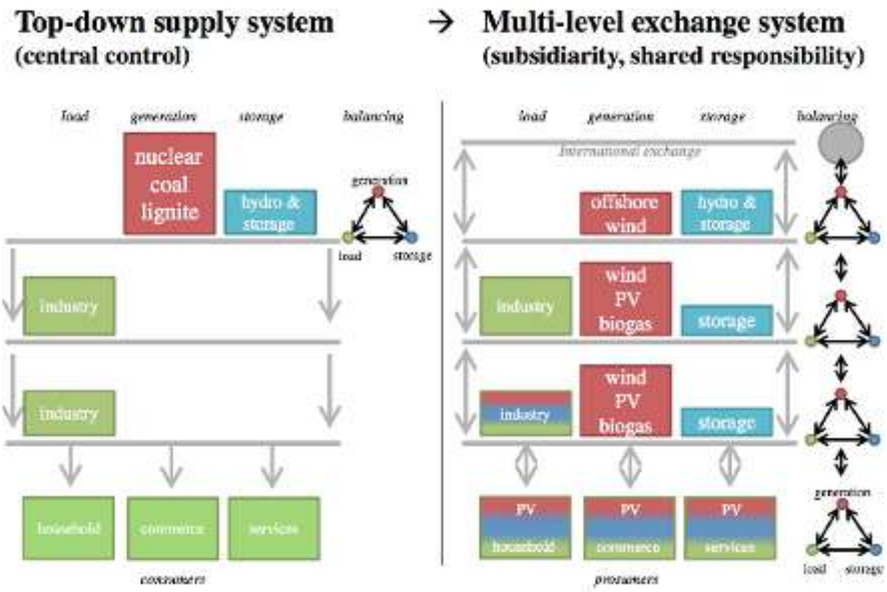


Figure 8. Transformation of the electricity system – schematic representation (Schleicher-Tappeser, 2012)

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.

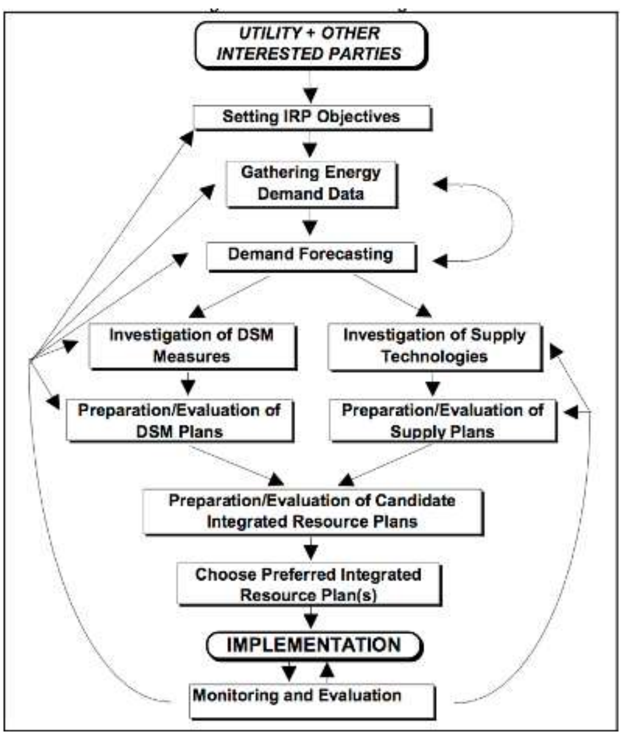


Figure 9. The Integrated Resource Planning process (Tellus, 2000)

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.

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