# Distributed generation

Implications for Australian electricity markets

Prepared for the energy supply association of Australia

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ACIL Tasman

Economics Policy Strategy

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# Executive summary

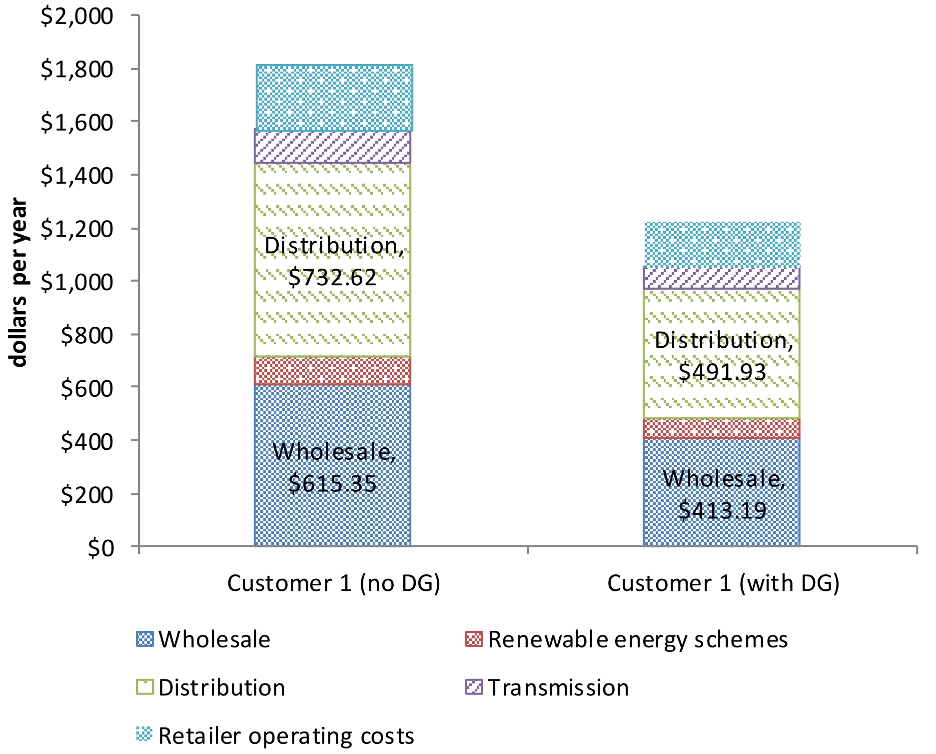
Most electricity in Australia, whether on the National Electricity Market (NEM), or the standalone markets in Western Australia and the Northern Territory, is generated by large-scale centralised generating units. However, an increasing amount is generated by distributed generators (DG) that are typically small in size (maybe very small, between 1-3 kW and as large as 10 MW) and located within the distribution system close to the consumers of the electricity they produce.

In recent years Australia has experienced rapid growth in the use of DG systems. This rapid acceleration has been driven by a range of factors, namely:

1. generous government subsidies
2. rapid reductions in capital costs
3. reductions in solar system installation costs
4. a distortion in the way electricity retail prices are structured.

The first three of these drivers are not likely to be as prevalent in future as they have been in the past. Therefore, the strongest driver of future uptake of DG systems is likely to be the ongoing distortion in the structure of retail electricity prices. In effect, customers are overcompensated when they generate electricity and use it on site because, in doing so, they avoid paying for electricity they do not need and, *in addition*, avoid making a contribution to the cost of providing network services. This is illustrated in Figure ES 1, which shows the electricity bill for two customers whose use of electricity is identical apart from the fact that one has a solar PV system. The electricity bill is broken into cost components, showing that a substantial part of the benefit of the solar PV system comes from the customer avoiding the contribution that they would otherwise make to the cost of network services.

Figure ES 1 **Retail electricity bills with and without PV system**




*Source:* ACIL Tasman

This overcompensation encourages uptake of DG systems beyond the efficient level. This has implications for the wholesale electricity market. More significantly it has two related implications for the cost other customers must pay for network services:

1. it reduces the total amount of electricity across which the cost of network services is 'smeared', thus forcing up the unit (per kWh) price of network services
2. it reduces the amount of electricity DG customers use, thus *reallocating* the burden of paying for network services to customers without DG systems.

While the DG system may also reduce a customer's use of network services, by reducing their demand at times of system peak, this cannot be assured and there is no link between the reduction in the amount they pay for network services and any change in the cost of providing them with those services. This is at the heart of the distortion.

There are also equity and fairness considerations. The former arise because some customers are unable to install PV systems, perhaps because they rent their home or live in an apartment. The latter arise because one customer's choice to install a DG system forces other customers to pay more for network services with no regard to either customer's use of network services.

This distortion could give rise to a 'price spiral' where the rising cost of electricity, driven by the ongoing reallocation of network costs, makes DG increasingly more and more attractive to customers. This spiral could be arrested and a fairer sharing of network costs achieved by reweighting electricity prices. There are a number of approaches to achieve this including increased fixed charges and time of use pricing. Each option will have different distributional impacts.

Reweighting tariffs would change the incentives to install DG systems as the network subsidy is unwound, giving viability to some projects that are not currently viable. If this coincides with further reductions in the cost of DG systems, or battery storage, a second spiral may ensue.

In the future if electricity sourced from DG systems becomes a genuinely competitive alternative to electricity sourced from the broader grid, the balance between the cost of remaining on the grid and the cost of withdrawing could drive substantial further DG uptake. Large numbers of customers may seek to withdraw from the grid, choosing to invest in DG systems instead. If this situation arises some pricing or regulatory response to the potential islanding of electricity consumers may be warranted.

# 1 Introduction

Most electricity in Australia, whether on the National Electricity Market (NEM), or the standalone markets in Western Australia and the Northern Territory, is generated by large-scale centralised generating units. These are typically between 30 MW and 750 MW in size and connected to the transmission system[1]. They are usually located relatively close to fuel sources for practical reasons (hydro, geothermal) or to minimise costs (especially coal fired facilities). Even where this is not the case (e.g. gas fired facilities) they tend to be located well outside population centres.

However, not all electricity generators are large, and not all are connected to the transmission system. Distributed generation, or distributed generators (DG) are generators that are generally small in size (maybe very small, between 1-3 kW and as large as 10 MW) and located within the distribution system close to the consumers of the electricity they produce.[2]

In recent years there has been rapid uptake of DG in Australia, which may continue in future. This has focussed attention on the possibility that the electricity grid may be much more distributed in future than it has been in the past. If this occurs, there would be very significant implications for existing electricity markets. The purpose of this report is to examine these implications in some detail.

Part of the reason that interest in DG has been high in recent years is that governments have strongly encouraged it. In recent years most Australian governments have implemented policies designed to increase the use of DG. Most have focussed on solar panels or other forms of zero emissions DG. They have provided encouragement through either subsidies (grants, rebates and upfront allocation of renewable certificates) or feed-in-tariffs.

These incentives are strengthened by the fact that electricity charges for small customers are heavily based on the volume of energy used even though the underlying cost of supply is largely independent of this.

1 While individual wind turbines are generally between 1 and 3 MW in size, wind farms as a collection of wind turbines are usually much larger.

2 Larger generation facilities may be embedded in the distribution system at or close to the consumers of the electricity that is produced. However, these are small in number, are generally associated with other large industrial or minerals processing facilities such as industrial sized co-generation supporting industrial processes such as paper production, alumina production and oil refining. These are not usually considered to be DG and are excluded from consideration in this report.

As subsidies have been reduced, and are likely to be reduced further, tariff structure incentives will play an increasingly important role in the future.

An additional factor is that the capital and installation costs of solar photovoltaic (PV) systems, the most prevalent DG technology in Australia, have fallen significantly in recent years.

Against this background, the esaa is seeking advice on six key questions, which are paraphrased below.

1. What is the likely range of DG technologies?
2. What are the implications for the wholesale electricity market?
3. Where would DG be adopted first?
4. How would increased uptake of DG affect customers?
5. How would increased uptake of DG affect regulated network services providers?
6. How should connection and disconnection costs be funded from both efficiency and equity perspectives?

This report is structured broadly around these questions.

Section 2 provides background information.

Section 3 addresses the impact on wholesale electricity markets and the likely range of technologies, addressing questions 1 and 2 above.

Section 4 provides a discussion of the likely impact on distribution networks and customers, addressing questions 3 to 6 above.

Section 5 provides a summary.

# 2 Background

## 2.1 A continuum of DG penetration

The future uptake of DG in Australia could be characterised as a continuum. It ranges from smaller-scale supplementation of energy needs to fully meeting a user's, or group of users', energy needs.

At one point on the continuum, households and businesses take up DG in sufficient quantity that they reduce the quantity of electricity they buy from their retailer significantly, but they remain connected to the grid to import electricity where necessary and export where available.

Further along the continuum, customers become substantially self-sufficient, although they do so in groups. In this scenario, groups of customers supply their own needs collectively. In a sense the group supplies its 'own' network (sometimes referred to as a 'micro grid'). The micro grid is connected to the broader network, although that connection may not be used often if at all.

At the end of the continuum, the uptake of DG is sufficient that customers form self-reliant 'islanded' networks of their own, or individual consumers become entirely self-reliant. As with micro grids, groups of customers supply their own demand for electricity entirely from DG systems. However, islanded users or networks are not connected to the broader grid at all. They must maintain their desired level of supply reliability without reverting to the grid for 'backup'.

Over the years customers have installed DG systems for many reasons. They have included financial incentives as well as environmental incentives given that DG typically produces less greenhouse gas emissions than alternatives and other incentives such as reducing reliance on large electricity companies.

In our view, the non-financial incentives are likely to remain stable over time and may have largely passed. That is, customers who wish to install systems for non-financial reasons have, by and large, done so already. However, the financial incentives remain and are subject to change. Therefore, in principle, substantial moves along the continuum of DG installations in the near term will be motivated by financial incentives to avoid retail electricity costs. Customers will be mostly unaffected by considerations of reliability as the network itself provides reliability. It follows that early moves to DG will be driven by the direct cost of generation technologies, whereas later moves will be sensitive to the costs of battery technologies and/or supply management systems for DG as well.

At 'later' points on the continuum reliability concerns become greater, with the need for some form of management to ensure that available electricity supply and demand are matched in real time. In the case of largely self-sufficient micro-grids, loads and supply across a range of users may be balanced more easily than for any single user, and therefore require only minimal use of storage or generation redundancy, whilst the network provides back-up supply of last resort. In the case of completely 'islanded' users or networks, substantial redundancy of generation or electricity storage (e.g. batteries) will likely be required to deliver the customer's desired standard of reliability.

For these later moves, customers' perceptions of the technical reliability of different supply options will also play an important role.

## 2.2 The impact DG has on the power system

There are two components to the contribution a DG system makes to the power system. First, the electricity it generates displaces energy that would need to be generated by another means. This gives rise to the energy value of distributed generation, which is discussed in section 2.2.1.

Second, because DG is located close to or at the electricity customer's premises, the electricity it generates need not be transferred as far or not at all over the network. This gives rise to the network value of distributed generation, which is discussed in section 2.2.2.

### 2.2.1 The energy value of distributed generation

When electricity is generated by a distributed generator it reduces the amount of electricity that needs to be bought on the wholesale spot market, that is, the distributed generator 'displaces' generation from other generators. There are two components to the value of this contribution:[3]

1. the (avoided) wholesale energy value
2. the value of reduced network losses.

A third factor which is often called the merit-order effect is at times argued to provide additional value to certain forms of generation including DG. When a DG system is built, it supplies energy into the electricity system thus 'loosening' the supply demand balance.[4] All else being equal the 'looser' supply

[3] It is useful to understand the value of the contribution, as well as the mechanism through which DG affects the power system to ensure that the value is weighed against the cost DG imposes on the market.

[4] In part the DG system reduces the demand placed on the system by its owner and in part it increases supply by exporting electricity to the grid.

demand balance causes spot prices to be lower than they would if the DG system had not been installed. For small systems the magnitude of the impact may be very small.

This effect, also called the price suppression effect, is the natural result of the change in balance between supply and demand. Whether a distributed generator causes the wholesale price of electricity to be reduced does not depend on its fuel source or whether it is renewable. It does not apply only to renewable generators.

The merit order effect (or price suppression effect) is a wealth transfer from generators to consumers. This transfer does not create economic value but simply redistributes it. In our view it is not appropriate to make explicit adjustments to the value of DG (or any form of generation) to account for the merit order effect.[5]

### 2.2.2 The network value of distributed generation

DG can provide 'network value', because, when electricity is generated close to or at the customer's premises, it need not be transferred through as many components of the network or not at all. An alternative to augmenting a part of a network to meet expected growth or to overcome an existing constraint is to install DG in the local area. This approach can defer the need for augmentation for some time until additional demand growth 'catches up' with the combined network capacity and DG.

The network value of DG is the difference between the cost of augmenting the network *sooner* and the cost of augmenting it *later* in present value terms.[6][7]

The network value of DG varies significantly depending on where the DG is located because the existing loading and likely growth in that loading on the electricity network relative to capacity varies across the network.

Electricity network infrastructure is typically built in large 'lumps' so there is often a significant lead time between network augmentation and full utilisation

5 For a more detailed discussion see Appendix A to our report to ACIL Tasman, "Modelling Feed-in Tariffs, the energy supply association of Australia", May 2012, available from www.vcec.vic.gov.au

6 Network value is not the same as the value of avoided network losses.

7 This value would be negative if electricity (peak) demand stopped growing sufficiently that the network need not be expanded in the foreseeable future. That is, the cost of upgrading the network *now* when it need not be upgraded *later* is substantial.

of that augmentation.[8] Therefore, while at any given time an electricity distribution network is likely to have some elements that are, or are soon to be, in need of augmentation, most elements are not likely to require augmentation in the near future.

Installing DG where an electricity distribution network is at capacity or is likely to soon reach capacity may potentially defer otherwise required network augmentation. Therefore, in these areas the network value of DG may be positive.

However, installing DG in parts of an electricity distribution network that are not at or close to capacity are unlikely to defer required network augmentation in the near to medium term. So the network value of DG in those areas is likely to be very small in present value terms.

A second issue that influences the network value of distributed generation is certainty. Non network solutions only defer network augmentation if they can be relied upon to support the network at the time that the network is at or close to capacity; that is, at times of peak demand.

A third issue that must also be considered in assessing the network value of DG is whether its use creates negative externalities (i.e. costs) for network users. As examples, the installation of DG may require modifications to the network to 'accommodate' the DG or may result in reduced power system quality such that it imposes additional costs on network users. In some cases, this could cause the overall network value of DG to be negative.[9]

A particular concern exists for electricity distribution networks which were initially designed for uni-directional flows. There is some evidence to suggest that DG systems actually increase network costs due to the bi-directional electricity flows associated with them.[10]

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8 This reflects the economies of scale associated with network infrastructure. That is, it is cheaper per unit of energy to build larger infrastructure, though the total cost is larger.

9 To our knowledge this has not been included in the various estimates of the value of PV output that have been made to date. This is partly because the network value would vary substantially within a network based on the local supply-demand balance and timing of the asset investment cycle. Therefore, the VCEC recommended that this value be compensated through a means other than Feed-in tariffs. In other cases, the task given to regulators has expressly excluded the network value. For example, in South Australia the legislation refers explicitly to the 'value to a retailer' of exported PV output. A retailer passes through any network value a DG system may provide without benefiting from it.

10 See for example submissions to the Victorian Competition and Efficiency Commission's Feed in Tariff Review from Jemena Electricity Networks (response to question 5), available from www.vcec.vic.gov.au

## 2.3 The structure of electricity bills and incentives for DG

While customers who install DG do so for a variety of reasons, there can be little doubt that the financial benefit of doing so is a key factor.

The majority of this financial benefit is that they can avoid paying the retail price for electricity they generate and use themselves. The financial viability of a DG system depends on how this compares with the installation and operation costs of the DG technology.

DG costs are clearly an important part of this equation. Another critical part of the equation is the way that electricity bills are structured.

In Australia, the retail price of electricity for small customers typically comprises:

- a relatively small proportion of the bill as a fixed supply charge usually set in cents per day
- a variable usage charge based on the volume of electricity consumed, in cents per kWh.[11]

A typical small customer's bill, or the price of an average unit of electricity, is mainly attributable to the variable charge. By contrast, a significant portion of the cost of supplying electricity to customers is fixed, that is, the cost is the same regardless of how much electricity the customer uses over time. The largest of the fixed cost is the cost of providing distribution network services, though retailer and some green scheme costs are also fixed.

Electricity distribution networks are built to maintain reliability to regulated standards, and therefore must generally meet the system's expected maximum, or peak, demand. In aggregate, the cost of supplying distribution services across a network is largely driven by the 'size' of distribution network required to 'deliver' electricity to customers at times of peak demand. Therefore, the cost of supplying distribution services to an individual customer is mostly driven by their demand when peak demand occurs on the relevant components of the network that are used to supply the customer.

The current practice of charging for fixed network services on a largely variable basis creates a substantial distortion in the incentive for installing DG. A worked example of this is provided in Appendix A.

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[11] In some cases the variable usage charge might comprise more than one 'part'. For example, some customers pay less for 'off peak' electricity used to heat water overnight. That usage is metered separately from their 'general' usage.

This distortion can be self-reinforcing. As customers use electricity they have generated themselves and avoid paying the full retail price they reduce the contribution they make to the aggregate cost of providing network services. However, the cost itself is not reduced, because, for the most part, the network was built before the DG was installed and the relevant expenditure is sunk. Therefore, the total cost of providing network services now cannot be changed. All that can be changed is the allocation of it between customers.

Whenever a customer uses electricity they generate themselves the (mainly fixed) cost of supplying network services is 'smeared' over fewer units of (grid-supplied) electricity. This happens regardless of the technology the customer uses to generate that electricity and regardless of whether that technology generates during peak times.

Therefore, as any form of DG system is used more widely the per unit (kWh) cost of providing network services must increase, driving electricity prices up further. As this happens, the financial incentive to install DG increases and a price spiral begins.

There is a logical limit to the spiral, because customers are unlikely to match their own use of electricity to the output of their DG system perfectly due to the costs involved. For example, household customers will not be able to operate entirely from a solar panel as it will not supply their needs at night time.

Under present market arrangements, electricity that is excess to a customer's needs at an instant in time is exported. Retailers earn revenue on this exported electricity when they sell it to a user other than the originating household at the full variable charge. When this happens the network earns the same revenue as it would have earned had that power been purchased on the NEM.

Further, recent government policy has been to ensure that this exported output earns a return closer to its energy market value (typically around 8-10 c/kWh) rather than the variable component of the retail tariff (typically around 25 c/kWh). This means that when DG systems do not match their associated load, their financial returns are lower, in turn constraining uptake of DG systems and the flow-on effects to network revenues and prices. However, as noted in chapter 3, the cost of PV may potentially fall to close to this level, making DG financially viable in its own right, while the energy component of retail electricity tariffs is likely to rise in coming years due to carbon pricing and increasing fuel costs.

This gap between the return on exported and own-consumed electricity also increases the financial viability of battery storage technology. A relatively small battery could improve a customer's ability to 'follow their load' using DG, enabling them to obtain a greater benefit than they would if they exported their excess output. This represents a further intermediate step along the DG continuum between true energy displacing use of DG and a largely self-sufficient user or micro-grid.

Therefore, moves beyond the early parts of the DG continuum, where users are still largely dependent on the network, towards complete islanding of grids and individual users will rely on either significant reductions in the cost of battery technology or improving cost competitiveness of DG technologies with output profiles that are at the discretion of the operator (see section 3.1).

## 2.4 Power of Choice review

In the final report of its recent *Power of Choice* review the Australian Energy Market Commission (AEMC) identified a range of issues that influence the development of DG under current market arrangements. These related to engagement between DG operators and network businesses and whether DG operators can capture the benefits of their system.

The AEMC noted that a number of other processes currently under way are addressing these issues so made few firm recommendations relating to DG in the Power of Choice review itself. However, it made several observations that are relevant to this report, which are summarised here.

First, the AEMC appears supportive of the concept that DNSPs should be able to own and operate DG systems themselves. In some jurisdictions this is already possible but in others (Queensland, Australian Capital Territory and South Australia) it is prevented or limited by arrangements for ring fencing regulated and non-regulated parts of a DNSPs business.

Broadly, the AEMC noted that sometimes "a DG asset may represent the most efficient option for augmentation of a distribution network,"[12] When this is the case, the AEMC considers that the DNSP should be able to use that DG asset, though certain safeguards may also be required. Some discussion of the way that DNSPs may use DG is provided in this report, in particular in Appendix B. The AEMC recommended (recommendations 18 and 20 in particular) that certain changes be made to the existing incentive regime to improve the incentives in this area.

12 AEMC, "Power of Choice review – giving consumers options in the way they use electricity" final report, p238, available from www.aemc.gov.au

Another issue that is discussed briefly in the Power of Choice review and in a specific rule change determination[13] is the role of a new category of NEM participant, a small generation aggregator. Broadly, participants in this type can aggregate the output of numerous small generators. This enables the small generators to participate in the wholesale spot market, whereas they now typically sell electricity to a market customer under a bilateral contract, usually for a fixed price. In effect, this introduces the possibility that small generators can be operated collectively as peaking plant and potentially increase their revenue. The generators to which this rule applies are not necessarily limited to DG, but the rule could potentially be applied to DG systems.

## 2.5 Where are we today, and where might we be going?

In recent years Australia has experienced rapid growth in the use of DG systems. By far the most commonly used technology today is solar PV. PV systems are now a common sight in most Australian cities, whereas they were rare only around five years ago. This rapid acceleration has been driven by a range of factors, namely:

1. generous government subsidies motivated by a desire to reduce greenhouse gas emissions and promote 'green' technologies. Subsidies have included rebates, feed-in tariffs and implicit rebates through the creation of renewable energy certificates
2. rapid reductions in capital costs in Australia driven by manufacturing innovations, increasing manufacturing competition and a strengthening Australian dollar
3. reductions in solar system installation costs largely driven by innovation in local installation businesses and emergence of a competitive mass-market for PV installations in Australia. This was driven, in turn by the scale effect of generous subsidies and reducing capital costs
4. a distortion in the way electricity retail prices are structured, as discussed above in section 2.3.

Government subsidies to PV systems have been unwound rapidly in recent years, so the first factor listed above is unlikely to be a major driver of DG uptake in future, although it has clearly contributed to the emergence of a competitive mass-market for PV today.

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13 AEMC, "Rule Determination - National Electricity Amendment (Small Generation Aggregator Framework) Rule 2012", 29 November 2012, available from www.aemc.gov.au

Further, the potential for further short-term cost reductions in modules and installations (points two and three above) is limited due to the low profitability of global solar module manufacturing and limited further economies of scale for the Australian installation industry. This makes future PV cost trends difficult to predict. As PV is the predominant form of DG in Australia at the present time, these changes are highly relevant for the immediate future of DG uptake in Australia.

Therefore, the strongest driver of future uptake of DG systems is likely to be the ongoing distortion in the structure of retail electricity prices. This driver will be exacerbated if network costs continue to rise at the rates seen recently.

Together with cost reductions observed to date and residual government assistance through the Commonwealth Government's Small-scale Renewable Energy Scheme (SRES) there may well be sufficient incentive to sustain a rapid take up of DG systems, albeit growing more slowly than it has done recently. Importantly, rapid growth in PV installations may occur in commercial and industrial facilities, moving beyond the established household market.[14]

In parallel with this ongoing uptake of PV installations, other technologies are providing new and potentially widespread DG applications. As discussed in section 3.1 the available technologies include gas-fired fuel cells and micro-turbines, and may include small wind turbines. Ongoing innovation in both DG and battery technologies sufficient to motivate full grid independence are plausible outcomes in the medium-term future in Australia. For example, increasing interest in electric vehicles internationally might spur rapid advances in battery technology. Gas fuel cells developed by Ceramic Fuel Cells Ltd in Australia using CSIRO technology are now being retailed under the marketing name BlueGen through Harvey Norman (albeit at very high price).

Naturally, rapid cost reductions for these technologies could drive their uptake similarly to DG. It is certainly not inconceivable that certain customer classes could have access to technologies that make genuine grid independence economically feasible within five years.

Detailed predictions of future DG installation rates and technology types is not the purpose of this analysis. Nonetheless there is sound reason to believe that the use of DG will continue to grow strongly, even if it does not accelerate at the rates seen recently. It is entirely plausible that future levels of DG penetration could materially affect commercial and regulatory outcomes in the

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14 These users benefit from the distortion, but have generally not been eligible for subsidies. As the distortion becomes greater, interest from this previously untapped segment may grow.

Australian electricity market. Anticipating the broad pattern of these effects is the purpose of the remainder of this report.

# 3 Impact on wholesale electricity markets

The impact DG has on the wholesale market is influenced by its output profile, that is:

- the quantity of electricity generated
- when it is generated.

That is, the system's output profile. In turn, this is influenced substantially by the DG system it uses and, in particular, by its 'fuel'. For example, solar panels are 'fuelled' by the light from the sun. Their output profile reflects this.

Section 3.1 provides a discussion of the main categories of DG system from the perspective of their output profile. Reflecting the impact that DG has on the electricity system, it is limited mainly to a discussion of the different output profiles that could be expected from generators of different technologies. The output profile of a DG system is of course also influenced by whether or not the system incorporates the capacity to store power, such as through a battery system. In effect a storage system gives greater control to the operator over when, and how much, to generate.[15]

Other than through the output profile, the technology underpinning a DG system would not change its impact on electricity markets and the power system.[16] This impact is discussed in section 3.2 provides a discussion of the possible impact DG may have on wholesale markets.

## 3.1 Likely range of DG technologies

From the perspective of their output profile, DG technologies can be placed into the following three groups:

1. Solar photovoltaic technologies
2. Wind powered technologies
3. Technologies whose output is at the discretion of the operator such as micro turbines or fuel cells.

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[15] Of course the storage system does not change when the system generates, but when its output is used. From a market perspective the effect is the same (all else being equal).

[16] We are assuming that any DG system eligible to connect to the power system would meet common standards relating to voltage and frequency of electrical output.

Figure 1 provides an overview of the status of technologies used for distributed generation.[17] The figures for micro turbines, fuel cells and battery storage should be treated as indicative as volumes are very small and case specific. Further, for technologies that are not yet commercial, the figures should be interpreted cautiously as they may be optimistic or may reflect costs that could be achieved by larger systems that may not be suitable as DG.

The figures for cogeneration and trigeneration are also highly case specific and sensitive to the assumptions made, including gas prices, capacity factors and heat rates. The assumptions for the figures shown in Figure 1 include a gas cost of $6/GJ, an operating life of 30 years, a capacity factor of 80% and a carbon price of $20/tCO_{2-e}$. We note that some studies have reported that capacity factors for such plants have not only failed to meet expectation but have also declined rapidly over time.[18]

[17] This report, and therefore this figure, are limited to technologies that may be used at the household level. Therefore the figure omits some well known distributed generation technologies, such as cogeneration and trigeneration, which are more suited to larger scale use.

[18] CPUC Self-Generation Incentive Program Tenth-Year Impact Evaluation, Itron, Inc. Davis, CA 95618, July 2011

Figure 1 **DG technology status and outlook**

| Technology | Market status | Scale of system | Current cost | Future cost | Comments | Estimated export value[g] |
|---|---|---|---|---|---|---|
| Solar PV | Commercially available (high volumes) | 1kW to MW scale | $224/MWh[a] | $133/MWh [a] (2020) | Flat plate no tracking. | $80 to $100 /MWh |
| Wind | Commercially available (high volume) | ~10kW to 5MW (per turbine) | $40-$100/MWh (for large turbines)<br>$80 - $300 / MWh [b] (for small turbines) | $62 – 233 / MWh[c] (2020) | Small scale wind system | |
| Micro turbine | Commercially available (low volumes) | 30kW - 200kW | $160 / MWh[d] | $190 / MWh[e] | Gas fired | $70/ MWh in 'always on' mode<br>Higher if operated as a peaker, though revenue is lower due to reduced volume. |
| Fuel cells | Early stage commercialisation. (very low volumes) | 1kW – MW scale | $150/MWh[f] | $90-110 / MWh[f] (mid term projection) | Natural gas fuelled. Can also provide hot water. | |
| Battery Storage | Commercially available | scalable | Very high cost and relatively short life (about 1000 cycles) | Li ion battery costs could fall significantly if EV use becomes significant. | Lead acid, Li ion | |
| Cogeneration | Commercially available | kW to MW scale | $98/MWh[h] | Costs are highly case specific | Gas fired | |
| Trigeneration | Commercially available | kW to MW scale | $66/MWh[h] | Costs are highly case specific | Gas fired | |

[a] Australian Energy Technology Assessment, Bureau of Resource and Energy Economics, 2012.

[b] http://www1.eere.energy.gov/femp/technologies/renewable_wind.html (accessed 17 January 2013)

[c] Assumes that costs of small wind turbines decline at the same rate as the BREE Australian Energy Technology Assessment suggest is the case for large turbines

[d] http://www.capstoneturbine.com/apps/econcalc/EconCalc2.asp?t=RF, http://www.nrel.gov/analysis/tech_lcoe.html

[e] Assumes that costs increase at the same rate as the BREE Australian Energy Technology Assessment estimates for a closed cycle gas turbine.

[f] Presentation by Chip Bottone, President & CEO, FuelCell Energy, June 2012, http://washingtonfuelcellsummit.org/proceedings/mornKeynote_bottone.pdf (accessed January 2012) FuelCell Energy's estimate based on natural gas cost of $8/mmBtu. Each $2/mmBtu change equates to about $10/MWh.

[G] based on ACIL Tasman, "Modelling Feed-in Tariffs", prepared for the VCEC, May 2012

[h] T. Foster and D. Hetherington, *Energy Market Design & Australia's Low-Carbon Transition - A case study of distributed gas power*, Percapita, Dec 2010.

*Note:* 1 mmBTU is about 1.055 GJ

For reference, Figure 2 provides indicative electricity prices for each Australian jurisdiction.

Figure 2 **Indicative retail electricity prices**

| Jurisdiction | Indicative price ($/kWh, GST inclusive) |
|---|---|
| Western Australia | $0.27 |
| Tasmania | $0.32 |
| New South Wales (AusGrid region) | $0.31 |
| Australian Capital Territory | $0.22 |
| Queensland | $0.24 |
| South Australia | $0.29 |
| Northern Territory | $0.23 |
| Victoria (indicative given no price regulation) | $0.29 |

*Note:* This figure provides a summary of *regulated* retail prices in each Australian jurisdiction as at 1 July 2012, the last time they were determined. It focuses on the typical bill of an average (hypothetical) customer in each jurisdiction as described by the jurisdictional regulator. The amount of electricity used by the average customer varies in each jurisdiction. These prices include the fixed component of each jurisdiction's regulated price 'smeared' across the assumed consumption.

*Note:* In Victoria retail prices are not regulated, but retailers must publish standing offer prices. For the most part those published prices are used as a starting point from which retailers offer discounts to customers on market contracts. Those discounts can be substantial. The price shown here is taken from the Australian Energy Market Commission's report on Household Electricity Price Trends, of March 2013, Figure 2. The price shown in that figure for 2012-13 is 31.9c/kWh. However, the AEMC states (in note 2) that the average discount from standing offer prices is 12 per cent, which means that the price reported here, 28.5 c/kWh, the price shown here, is a more realistic reflection of the price Victorian customers pay for electricity, though the actual price paid by individual customers could be higher or lower depending on the arrangement they have reached with their retailer.

The first two groups, solar and wind, have the common characteristic that they generate automatically when fuel is available, but that the operator has no control over when that occurs.[19] These two groups use different fuels and, therefore, have different output profiles.

The third group is distinguished from the first two by the fact that the operator has substantial control over how much electricity will be generated at a given time. It encompasses a wide range of technologies. It is also discussed in more detail below.

### 3.1.1 Solar photovoltaic technologies

Solar photovoltaic is by far the most common form of DG in Australia. This technology underpins the rooftop solar panels that are now common in all of Australia's cities. In the last few years there has been very rapid expansion driven first by Government subsidy and later by feed-in tariffs, the Renewable Energy Target and the Small Scale Renewable Energy Scheme.

The output of a solar photovoltaic system is a function of the surface area of the panel, its technical efficiency and the insolation, or amount of light that falls on it. In turn, insolation to a particular system depends on a range of

[19] The operator may be able to prevent the system from generating when fuel *is* available, but cannot force it to generate at other times.

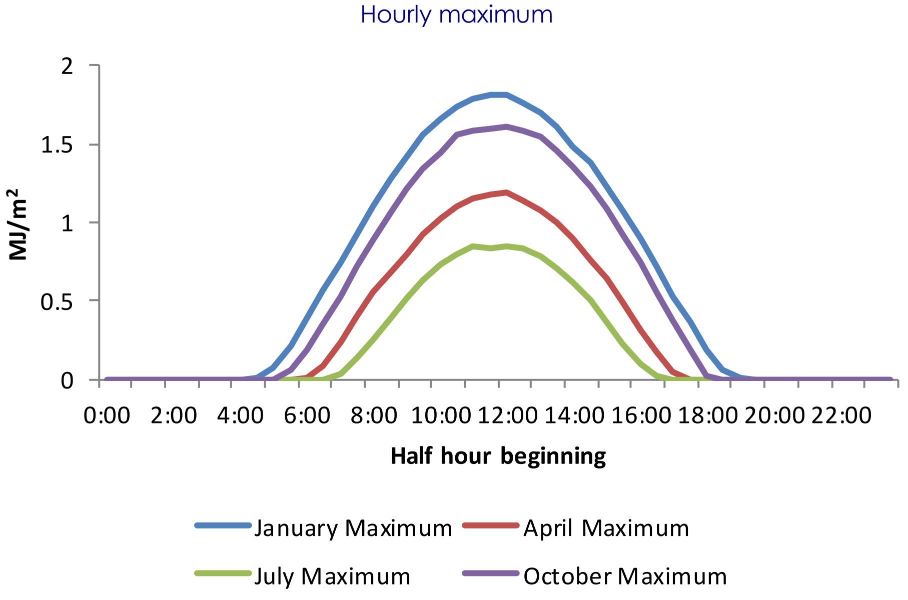
factors ranging from latitude and climate to cloud cover at a particular time and the size and proximity of trees and other objects that may cast shade on the panel.

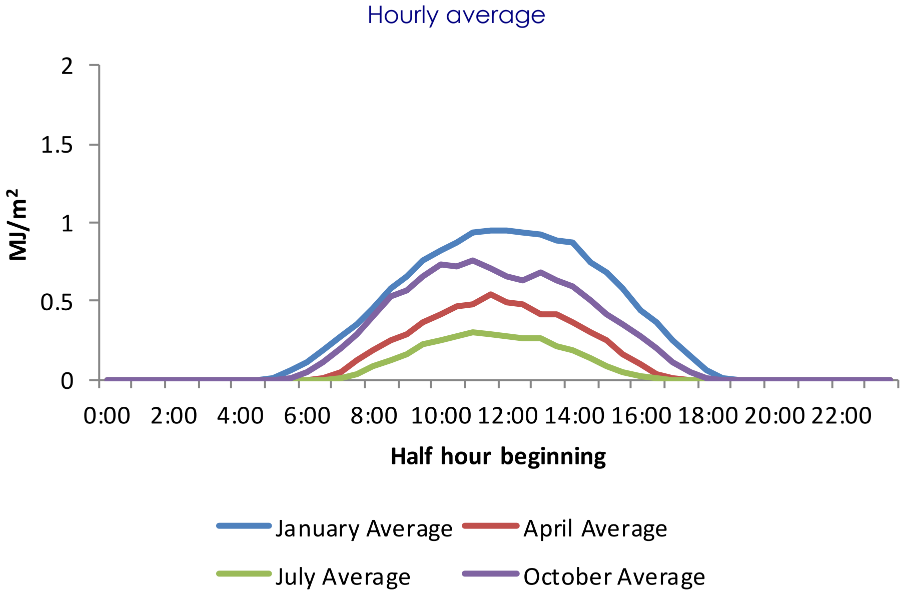
For example, Figure 3 illustrates the solar insolation as observed by the Bureau of Meteorology at Melbourne Airport in 2010, 2011 and 2012. To account for daily variability, the figure shows the maximum, minimum and average insolation observed during each half hour of the day on a monthly basis.

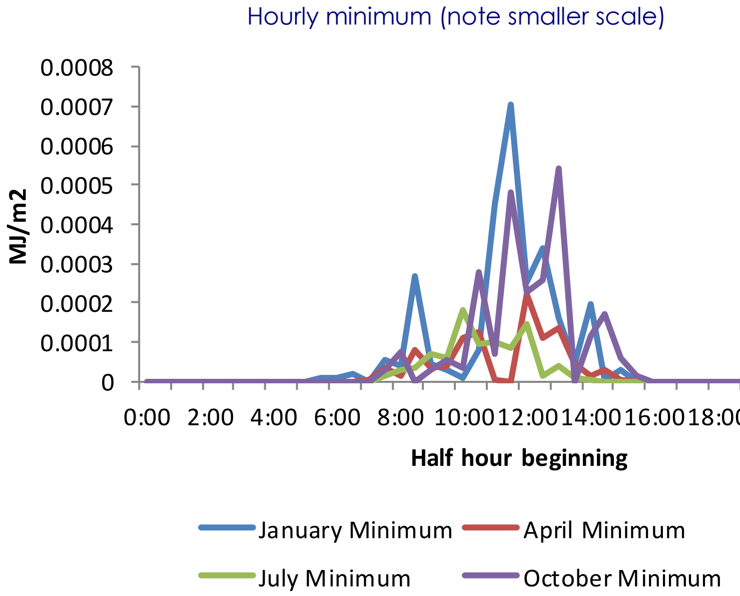
Broadly, the pattern illustrated in Figure 3 is as would be expected. In particular, insolation beings later in the day and is generally lower during the cooler months. It starts earlier, lasts later and is generally higher during the warmer months. However, the third pane of Figure 3, which shows the hourly minima, shows that insolation[20] can be very low at any time in the year. This has potentially severe implications for the reliability of photovoltaic DG systems.

[20] Solar insolation is the amount of solar radiation that reaches the earth's surface. In a sense it is the fuel that a solar PV system uses to generate electricity.

Figure 3 **Solar insolation profile – Melbourne airport**





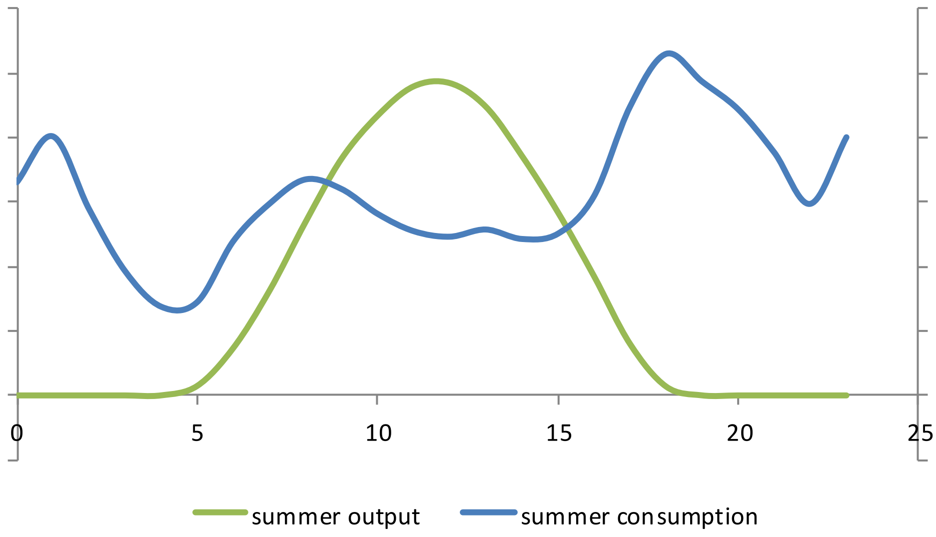

A comparison of average household demand and representative PV output is shown in Figure 4. This gives an indication of the relationship between the (gross) output of a solar PV system and household electricity consumption. It is based on solar insolation at Melbourne Airport as shown above and the Net System Load Profile for the same area.[21]

Comparing the two is difficult because the output of a solar PV system depends on the size of the system as well as insolation. For this reason, no units are shown on the figure.

The figure does show clearly that in summer the peak in solar output (insolation) occurs earlier in the day than the peak in residential demand.

[21] The Net System Load Profile is averaged over the summer period (November to March).

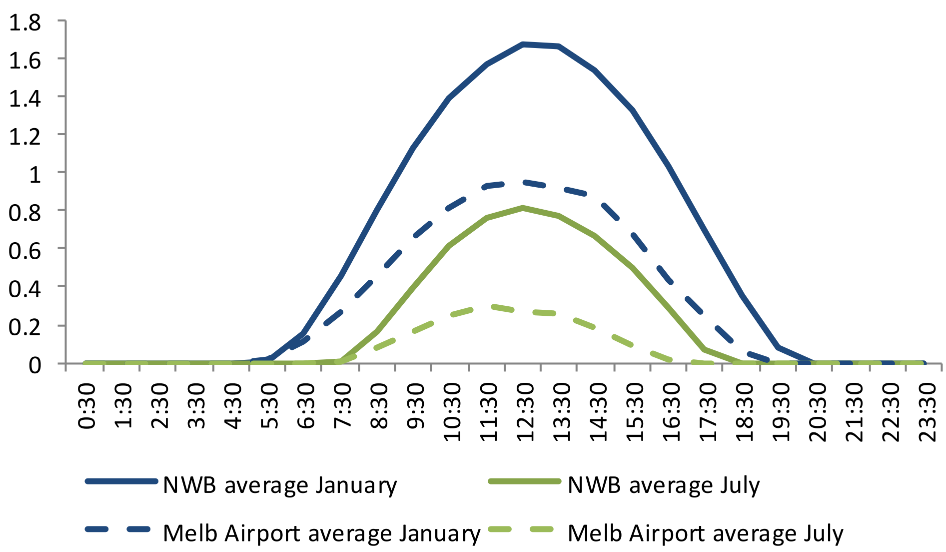
Figure 4 **Timing of solar output and demand peaks**




*Source:* ACIL Tasman

The level of solar insolation changes with latitude and other climatic conditions, though the shape tends not to change as much. This is illustrated in Figure 5, which shows the Melbourne airport average insolation for January and July alongside corresponding data for North West Bend in South Australia.

Figure 5 **Solar insolation at Melbourne Airport and North West Bend (SA)**




The difference in insolation in various parts of Australia is reflected in the Renewable Energy Target and its predecessor schemes, which have divided

Australia into four zones for the purpose of deeming the amount of electricity a typical solar photovoltaic DG system would generate in different places (on a capacity installed basis).[22]

The electrical output of photovoltaic systems is not necessarily directly related to insolation, in particular because the angle on which the system is installed and ambient temperature at the time of generation are relevant. For some purposes it will be important to consider the possibility that some of the output of the system may be used 'on site', with only a proportion of the total electrical output exported to the grid. For other purposes, such as assessing the impact no peak demand, this may not be relevant.[23]

However, for present purposes, it is reasonable to associate the profile of insolation with the output profile of a photovoltaic system.

### 3.1.2 Wind powered technologies

The second category of DG is a wind turbine.

There are numerous forms of wind powered electricity generators distinguished by details of the turbine such as the axis (vertical or horizontal) and the nature of the blades.

Wind power has undergone a very rapid increase in Australia over the last decade, largely due to the Renewable Energy Target and its predecessor schemes. Some of the windfarms that were built during that time are technically classified as distributed generation as they are connected to distribution networks. However, as noted above, these generators are not the focus of this report.

At the smaller scale, wind power has not been highly successful in Australia. The number of small wind systems installed in Australian cities is very small compared to the number of PV systems.

This lower level of uptake may in part be because wind turbines were not eligible for all of the Government support mechanisms that were provided for photovoltaic systems. It may also be due to technical difficulties with the systems and installation requirements, both physical and otherwise, that made wind power less attractive than the alternative.

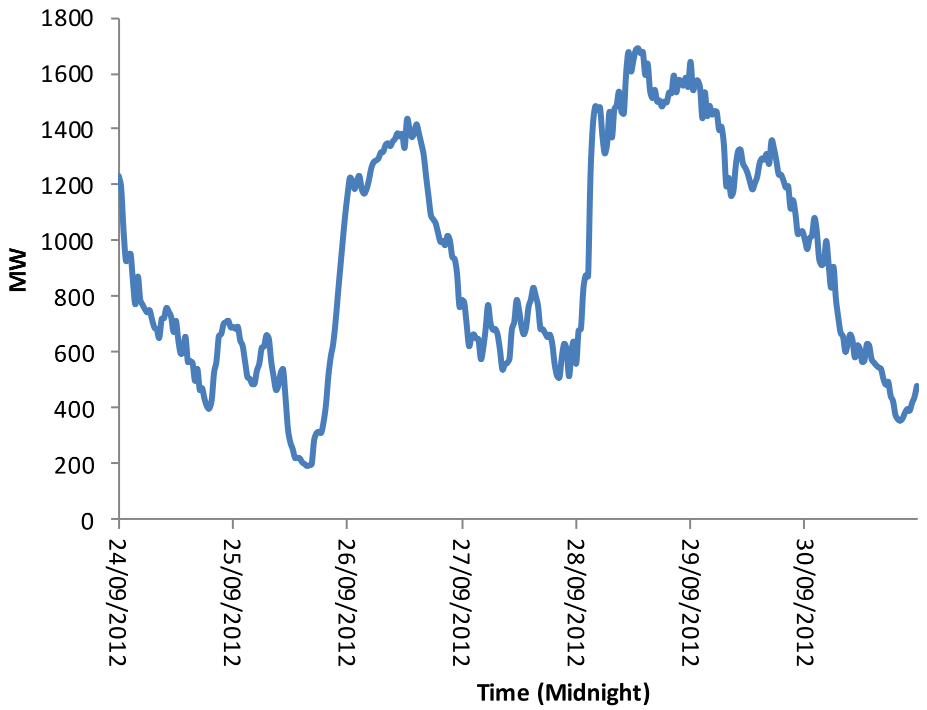
22 The total energy output is reflected by the area under the insolation curve.

23 Note that demand on the network is reduced by a DG system regardless of which customer uses the output. The issue is that the network need not transfer as much electricity into the area.

Similarly to photovoltaic systems, wind generators have an output profile that is dictated by the weather. The available data about the output of small wind turbines are limited, reflecting the fact that relatively few have been installed in Australia. It is informative to consider the output of the large scale wind farms currently installed in the National Electricity Market.

Figure 6 shows the output of the various wind farms in the NEM in the week ending 30 September 2012. It shows that the output of wind generators is highly volatile and less predictable than photovoltaic systems. It should be noted that the data plotted here are the total output of 19 wind farms in different locations across the NEM. With this many wind farms, the volatility in their output is averaged out to some extent. A smaller number of turbines installed in a built up area for use as a distributed generator may exhibit greater volatility.

Figure 6 **Output of all NEM wind farms, 23 to 30 September 2012**




*Data source:* Australian Energy Market Operator

### 3.1.3 Other technologies

There are many technologies other than photovoltaic and wind that could potentially provide DG. DG systems could potentially be powered by fuels including bio-waste, bagasse, natural gas or liquid fuels. However, the most likely DG technologies relevant to this study are natural gas fuelled micro turbines or fuel cells. Both these technologies are capable of producing heat that can be used for space or water heating.

The unifying characteristic of these forms of DG system is that they have load shapes that are within the control of their operator. In other words, if the operator saw fit to do so, they could be used in 'always on' mode, generating the same amount of electricity at all times or in a variety of other ways. For example, their output may be increased when the output of other generators falls, when demand increases of when the price they are paid is high.[24] They can also be used in conjunction with more intermittent DG systems to provide more reliable supply.

Another technology that is potentially very important to the uptake of DG is electrical storage. Storage systems can be used in conjunction with any of the DG systems discussed above to store power that is surplus to demand and provide power when an intermittent DG system cannot generate.

In practical effect, storage gives increased flexibility to the operator of DG systems. For inherently intermittent technologies such as solar and wind, storage can give the operator the ability to 'flatten' the load profile and supply electricity when the generator cannot operate.

Storage may also be used to allow systems to be taken out of service for maintenance, planned or unplanned, without interruption the supply of electricity.

### 3.1.4 Summary of DG technologies

In summary, there is a wide range of technologies that are, or could be, used for DG. Some are already in widespread use in Australia while others are less well developed.

For the remainder of this report we take a technology neutral approach. In other words, we proceed on the basis that the impact DG will have on electricity markets and customers in those markets depends on its output profile and reliability, but not on the particular technology.

## 3.2 The impact of DG on wholesale electricity markets

It is the incentives that lead new DG to enter the market rather than the DG systems themselves that define the impact they will have.

24 Different technologies, and different applications, will have different degrees of flexibility.

The very large majority of generators in the NEM participate in the central dispatch system that is managed on a half hourly basis by the Australian Energy Market Operator (AEMO).[25] They place bids to supply electricity at prices of their choice and generate when required to do so by AEMO.

The auction processes in Australian electricity markets are designed to compensate generators for the value of the electricity they generate and to provide signals to new generators when entry is required. They do this through the price generators are paid in the auction process. Generally speaking, as demand grows, average wholesale prices rise until a point is reached where entry can be sustained. When that entry comes, the new generator increases the available supply and reduces the wholesale price of electricity below what it would otherwise have been.

Unlike centralised generators, DG systems do not participate in the wholesale market.[26] They do not make bids and are not dispatched by AEMO. They are not paid the wholesale price for the electricity they generate. Many DG systems were installed in response to incentives delivered through premium solar feed-in tariffs that reflected Governments' desires to support technologies and to empower small customers rather than to deliver electricity in the long term interests of those customers.

This has the potential to change their impact on the wholesale market dramatically because DG responds to signals from outside the wholesale market that do not necessarily reflect market conditions.

As discussed in section 2.3, the dominant incentive for installing DG in future will be the distortion arising from the structure of retail electricity prices. With current pricing structures, there is a real chance that DG will continue to be installed at a high rate.

The power system is currently oversupplied for the underlying economic and market conditions. DG has been one of a number of contributing factors to this oversupply. Though it is likely to have been a small factor, it has grown substantially in recent years. [27] Therefore, wholesale market prices may be suppressed by subsidised DG.

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25 Generators are dispatched every five minutes and price is set on a half hourly basis.

26 There are some generators that are connected to the distribution network and also participate in the wholesale market. These are not generally considered to be distributed generators, and are beyond the scope of the analysis here.

27 The recent economic downturn has also contributed.

While any suppression of prices that may have been caused by DG may appear to be in customers' short term interest the cost of the subsidy itself must not be overlooked. The total increase in the cost of electricity supply more than outweighs the reduction in wholesale price. Further, the longer term interests of customers are jeopardised by policies of this type to the extent that they reduce investment certainty and therefore defer investment in new, lower cost generation capacity.

The impact of DG on prices will continue for as long as the feed-in tariffs, most of which will be paid to existing customers for many more years. This will have ongoing impacts for the power system through the suppression of incentives for new generation. It may also lead to further mothballing of plant and possibly even the closure of some existing plant.

Another characteristic of DG that could have a substantial impact on generators is that it is typically more intermittent than a large scale centralised generator.

From a wholesale market perspective, most DG systems would be considered intermittent. As discussed below, this is inherent in solar and wind powered DG systems. Operators of those systems cannot generate when their 'fuel' is not available. Other generators, such as micro turbines or back-up generators in large buildings, are intermittent to some extent because their operation is subject to the decisions of their operators rather than AEMO.

Generators cannot be certain of the quantity of electricity they will sell in any given interval or of the price they will receive. Demand for electricity is volatile, varying every five minutes for a wide range of reasons. Generators routinely manage the risks arising from this and the fact that prices are also volatile.

At low levels of penetration, the intermittency of DG is likely to be 'lost' in the natural intermittency of electricity demand. However, as penetration increases, this could add to the volatility of electricity demand.

All else equal, intermittent generation can place upward pressure on the wholesale price of electricity as it increases the need for relatively expensive fast start (peaking) generators such as open cycle gas turbine while eroding the viability of relatively cheaper base load plant. This would be offset by downward pressure on price if the intermittent generation has a lower cost than the generation it displaces, so the net effect could be in either direction depending on the specific details.

### 3.2.1 The differential impact on the continuum of DG installation

In the NEM electricity is traded at the Regional Reference Node. Therefore, within a given region the impact a generator has on the market is the same regardless of its location. The only slight exception is that some generators will experience less transmission losses than others.

By definition, DG is not subject to transmission losses. Therefore, it makes no difference from a wholesale market perspective whereabouts within a given distribution network the DG is located. It follows that the impact on the wholesale market of a group of DG systems would be the same whether they form an islanded network or a micro grid or whether they are scattered throughout the network.

In the future, if DG systems enter the market in response to conventional price signals from the wholesale market the effect would be no different than that arising from the entry of centralised generators with similar characteristics.[28] On the other hand, if DG 'follows' the existing distortion in retail prices or other policy intervention, it will continue to increase the total cost of wholesale electricity beyond the efficient level.

Currently the latter pattern is in place, with DG being installed in response to the inefficiency in the retail price of electricity. This is likely to continue unless retail prices are restructured to reflect the underlying drivers of cost. This was noted by the Queensland Competition Authority (QCA) in its draft report regarding the fair and reasonable value of a feed-in tariff for PV. The QCA said that:

> Network tariff reform is a further option to be considered as a means of more equitably sharing the costs of the scheme. Specifically, there may be scope for distribution businesses to establish new, cost-reflective network tariffs for PV customers which ensure that these customers are charged their full fixed-network costs, which are largely avoided under the present network tariff arrangements.

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[28] As discussed below the fact that DG systems tend to be intermittent would have some impact.

# 4 Impact on distribution networks and customers

The effect of DG on distribution networks, retailers and customers are sufficiently inter-related that the four questions posed by the esaa relating to how DG affects these elements of the electricity market are dealt with together in this section.

## 4.1 Where will DG be adopted?

Our expectation is that, all else being equal, customers will install DG where they have the greatest incentive to do so. In practice, we expect that the key driver will be financial incentives, although other incentives will also play a role in some cases (such as environmental preferences or concerns about network reliability vis-a-vis the reliability of DG).

There are three components to the financial value a DG system gives its owner:

1. avoided retail price of electricity generated and used on site
2. sale price of electricity exported to the grid
3. value of renewable energy certificates and other renewable energy subsidies such as feed-in-tariffs (if applicable).

None of these distinguishes between areas where the network is congested and areas where it is not. In particular, the practice of 'postage stamp' electricity network pricing for small customers is important. This practice means that customers of the same class cannot be charged different network prices for different locations. The result is that the financial incentive to take up DG does not typically vary within a given network.[29] Therefore, there is no greater incentive for customers to install DG where its network value is highest.

It follows then that there is no reason to expect that DG will be installed where its network value is greatest, or even where its network value is positive. The likely result is that DG take up will be scattered randomly throughout

[29] Strictly speaking the DNSP charges the retailer the network charge. The retailer is permitted to charge different customers different prices and could potentially distinguish the price it charges customers based on their location. However, given that this is not reflected in the network charge as paid by the retailer there is no incentive to do this and indeed doing so would introduce a significant risk for the retailer.

networks, rather than concentrated in areas where it has particular network value.[30]

One possible exception to this is that some customers in rural areas may have significantly worse reliability of grid electricity than typical urban customers. These customers in particular may see benefit in installing DG for reliability support. Another possible exception is that new subdivisions might pursue weakly grid-connected or completely islanded micro-grids using DG to avoid the upfront cost of building internal network infrastructure to service this load. However, both of these more location-driven moves towards DG are likely to only represent a relatively small portion of total load, and so do not undermine the general point of relatively random distributions of DG connection within a given network.

This conclusion assumes that the DG is to be adopted by the customer. It could also be adopted by DNSPs, in which case the locational incentive to use DG as a means of network support is stronger and a more location-driven pattern of DG uptake would be observed. This is discussed further in Appendix B. This specific application of DG technologies appears relatively limited in scale when compared to mass-market take up DG in response to financial incentives.

By contrast, network prices differ between individual distribution networks. For the most part the more sparse the region the higher the average cost per customer of providing distribution services and, therefore, the higher the price of those services. Assuming that the portion of fixed and variable charges is relatively constant across networks, we would assume networks with higher supply costs to experience higher levels of DG penetration, all other things equal. Similarly, networks servicing areas where the wholesale cost of electricity is higher would also see greater financial incentives for DG.[31]

In the specific but important case of PV, capital costs have declined to the point that insolation rates are less important drivers of DG location than they used to be. In the past, to obtain a reasonable financial return from the high upfront cost of installing a PV system, good solar orientation and a strong

[30] Broadly speaking, we also think it is impractical to develop extremely refined, location-specific network tariffs that would accurately reflect the marginal cost of consumption at a point in time. This value would change dramatically over time and be generally confusing and unacceptable to users, policy-makers, regulators and possibly network businesses too. Therefore, our working assumption for this report is that postage stamp pricing will remain essentially unchanged in operation, with some limited differentiation (e.g. as seen in the Ergon network in Queensland).

[31] This assumes that that the higher wholesale prices are reflected in retail prices and that they are not suppressed by price regulation at the retail level.

solar resource was essential. Low capital costs have changed this. Nevertheless, installation rates in Tasmania are still low compared to the mainland and high insolation rates appear to have sustained the PV industry more strongly in Queensland than in other locations.

## 4.2 The impact of DG on consumers

The key impact on retail customers of an ongoing expansion in the use of DG would be the price spiral described in section 2.3. As an increasing number of customers switch to DG for a larger proportion of their electricity use the base over which network costs are recovered would shrink. This would drive up prices in per unit terms and increase the contribution that customers without DG, or those who use it less, make to the mainly fixed cost of providing network services. This in turn increases the incentive for the remaining grid-users to adopt DG, creating the spiral. This effect would occur in much the same way whether DG is taken up by scattered individual users, as we consider most likely, or in the more concentrated form of micro-grids and islanded networks.

The solution to this would be to reform network tariffs to ensure more equitable and sustainable outcomes. There are a number of ways this could be done. For example, charges could be based on parameters including:

- measured peak consumption (requiring time of use meters)
- measured consumption at the time of peak system load (also requiring time of use meters)
- the maximum or rated capacity of a connection point.

Alternatively they could be structured as a simple supply charge applied on a $/day basis and differentiating between broad customer classes.

As a means of addressing the distortion in electricity retail prices, the simple supply charges have two strong advantages over more complex peak demand or capacity based charges.

The first advantage is that they are simpler because they lack the complex administrative and metering requirements of peak demand or capacity based charges, which would be costly and impractical for small users.

The second advantage exists because of the sunk nature of the investment in electricity distribution networks. That investment was made based on a particular outlook of forward electricity demand and now cannot be undone.

While *future* investment could potentially be avoided using network tariffs that moderate growth in peak demand, sunk *historical* investment cannot respond to these signals.

While the sunk cost in network infrastructure cannot be reduced, the way that it is recovered has distributional consequences between customer classes rather than clear economic efficiency effects.

By contrast to the sunk investment in existing infrastructure, the future cost of DG installations can be avoided. Reweighting network tariffs to fixed charges based on individual customer demand would allow DG that operates at times of peak demand to also avoid a high proportion of network charges, and therefore provide a strong financial incentive for such investments. However these systems cannot change past network investment costs so this type of reward would artificially encourage DG of this type. On the other hand, simpler supply charges set independently of changes in actual demand do not create such a distortion.

The effect of a reweighting in network tariffs is illustrated in Figure 7.

First, consider a customer with annual consumption of 6,500 kWh. Assuming that the retail price of electricity is 28 c/kWh, disregarding the fixed component that customer's annual electricity bill would be $1,820. This is shown in Figure 7, with the main cost components identified individually.[32]

If the customer installs a 2.5kW solar PV system we estimate that they would generate approximately 3,000 kWh of electricity and consume approximately 2,100 kWh on site. Therefore, with current tariff structures, their annual electricity bill would fall to $1,222 as shown in the second column in Figure 7. Note that we have not included any payment that the customer may receive for electricity they export to the grid so, in a sense, their annual bill is overstated here.

On the other hand, if tariffs were reweighted so that the customer made the same payment for distribution services as they had done before the DG system was installed, their bill would be as shown in the third column. In effect, when this customer uses electricity from the PV system 'on site', they avoid paying the wholesale energy value of that electricity but do not avoid paying for other cost components. In this case the annual bill would be $1,550.

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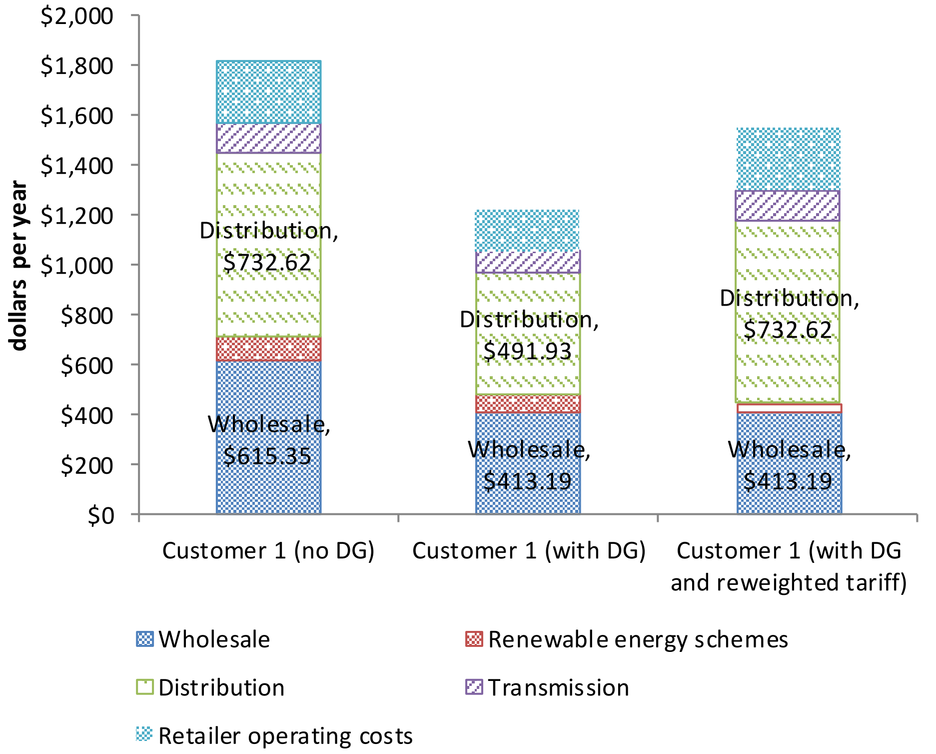
32 The breakdown is based on proportions estimated by the AEMC.

Figure 7 **Impact of a DG system on customer bill with reweighted tariffs**




We understand that DNSPs currently have a degree of control over the structure of their tariffs, which may enable them to pursue this strategy should they wish to do so. Of course, this would not be without implications for other participants. In particular, electricity retailers are the interface between customers and DNSPs in most cases. While retailers are under no particular obligation to 'mirror' DNSP's fee structures in the price they charge customers the commercial reality is that they almost certainly would do so. Therefore, if DNSPs made a substantial change to tariff structures, retailers would almost inevitably need to deal with substantial interest, and possibly objection, from customers. We understand anecdotally that past moves towards charging higher fixed component of electricity tariffs has faced opposition from a variety of user groups, including owners of holiday houses, which tend to have low average demand and therefore would incur higher network costs if tariffs were levied on a fixed rather than variable basis.

While a reweighting of tariffs could possibly be implemented on a voluntary basis by DNSPs, the efficacy of this type of voluntary approach may be limited.

This reweighting would be to the benefit of customers with relatively large energy use and the detriment of those with relatively small energy use (within a customer class). The former would include larger households with high average usage.[33] The latter would include both small households and households that have already installed a large DG system.

This type of network tariff reweighting would be particularly effective in screening out DG projects that rely on the distortion in electricity prices for their financial viability. As discussed in section 2.3, this distortion is a critical driver of present PV installations, which rely on avoided network costs to be financially attractive to end users. This is likely to remain the case for the immediate future. With reweighted tariffs these projects would be distinguished from projects that are viable based on the benefit they deliver.

Notwithstanding that it would have this screening effect, the central argument in favour of such a reweighting is not that it would protect DNSP revenues or slow the rate of increase in network tariffs. Nor is the argument in favour of it tied directly to DG of any particular form. The distortion discussed here also shelters customers who make significant increases in maximum demand, for example by installing large air conditioning systems, for the cost of their decisions. The central argument is that if network tariffs were structured this way they would better align with the cost of supply and, therefore, lead to a more efficient use of resources in aggregate. Therefore, structuring prices in this way would further the National Electricity Objective.

The reason is that the existing network assets are sunk. They cannot be turned to alternative uses. On the other hand, the as yet unmade investment in DG systems can be avoided.

If the sunk cost of the network is recovered on a largely variable basis that increases the financial attractiveness of incurring these avoidable DG costs, instead of utilising the available network asset, society as a whole would incur greater costs as it built additional (DG) infrastructure that is largely unnecessary.[34] In aggregate, society would be better off if the new avoidable costs are not incurred.

Overall, the impact of increasing DG penetration with current tariff structures creates a clear transfer of the burden of paying network costs from DG users to non-DG users. That transfer is not connected to the cost of supplying those two groups of customers with those services. A rational tariff restructuring would allow society to incur a smaller aggregate cost for electricity supply,

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33 We are assuming that peak demand charging to reflect, for example, the usage of large air-conditioning systems in many wealthier, high energy using households, is not politically or technically feasible at the present time.

34 Note that this is the case even if the DG would have been a more efficient approach in the first place.

although there would be some redistribution of wealth between electricity users.

As this mechanism is broadly available to network businesses and is likely to be effective in halting the present network price spiral caused by uptake of DG, our subsequent discussion in this report assumes that such a restructuring of network tariffs will occur.

## 4.3 Arrangements for network disconnection

The discussion in the previous section deals with DG to the point that it can match grid reliability at comparable cost. If network tariffs are restructured to more closely reflect the fixed nature of network costs, only DG technologies that can compete with the truly variable costs of electricity supply will be competitive. At the moment, it is unlikely that many technologies will be able to do so.

However, in future, DG may come to a point where it can match grid reliability and compete with the full long-run cost of electricity supply (i.e. fixed and variable components). If it does, a range of new dynamics would emerge.

At the point where DG is effectively competing with networks on both cost and reliability without implicitly relying on networks to balance generation and consumption, the potential for unsubsidised islanding of individual users or small networks emerges.

This situation could also lead to a new network price spiral even if the restructuring of network tariffs described above had been done.[35] This spiral would ensue if network businesses persist with (reweighted and now largely fixed) tariffs at levels designed to recover their regulatory revenue allowance. If DG can provide customers with electricity more cheaply than the cost of buying it from the grid (including network prices determined earlier) they have a strong financial incentives to adopt DG.

The new balance between the cost of remaining on the grid and the cost of withdrawing could drive substantial further DG uptake and large numbers of customers may seek to withdraw from the grid, choosing to invest in DG systems instead.

As discussed above, this situation would lead to an inefficient replication of resources and would be undesirable. It could also result in large-scale

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35 If it is not, the incentives are stronger.

disconnection of users from the network, raising a range of economic and regulatory issues.

The most acute issues will be how these disconnections are treated within the existing framework of economic regulation of networks, and what costs and conditions might be applied on the act of disconnection. As is shown below, these two issues are related.

As discussed in section 4.1, it seems likely that network disconnections will be relatively randomly scattered within any given distribution network area. Therefore, the primary issue facing network regulation is not that discrete elements of the network will become 'disused', which might imply writing off and physical disconnection of specific pieces of infrastructure. Rather, the primary issue would be an increase in the amount of 'under-used' network infrastructure.[36]

This relates to the discussion in section 4.2 above. If the entire network is effectively at risk of being by-passed by a broad range of customers, a rational response of the network could be to forego revenue across the network to retain customers, rather than identifying specific hot-spots where disconnection is most likely.

This perspective of broad, network-wide pressure on DNSP revenues is consistent with our view of the nature of the regulatory bargain struck between a DNSP and its regulator (on behalf of customers) whenever a specific network asset is built. In the case of any specific capital investment approved by the regulator in a network determination, the regulator is confirming, at least implicitly, that the projects to be funded are prudent and efficient and should be undertaken based on the best available information at the time.

As assets became *under* used (or even *un*used), we can imagine that the regulator would come under pressure to write down the value of the DNSP's regulatory asset base to the level that seems prudent and efficient *with the benefit of hindsight*.

The argument would be that the DNSP's regulatory asset base should be revised down to reflect what is necessary to supply the load that is now

[36] The exceptions would primarily arise where the cost of maintaining an identifiable part of the network exceeds its value to an identifiable customer or group of customers. In this case, DG would in fact be preferred to maintenance of the network. However, given networks have recently undergone, or are undergoing, a massive reinvestment and upgrade in reliability standards, and incur relatively low ongoing maintenance costs, these circumstances seem quite limited in the short to medium-term.

reduced by the presence of DG systems.[37] It would be argued that it is inefficient for customers to pay for assets they no longer need, especially since they have already invested in an alternative. For *un*used assets it would also be argued that it is unreasonable to ask customers to pay for assets that nobody needs.

In our view it would be detrimental to the efficient operation of network businesses, and therefore the broader electricity market, if this argument was accepted.[38]

To argue that customers should be able to benefit from hindsight in this way is equivalent to saying that a householder who has their house renovated and then decides to demolish it when the renovations are only halfway through their useful life should only pay the builder for half of the cost of the renovations. In most markets, such as markets for home improvement, this argument would not be accepted. It is only conceivable in this case due to an unusual characteristic of network markets, namely that investments are made by DNSPs first and paid for by customers later.

If DG customers are able to withdraw from the grid and walk away from the implicit commitment that was made on their behalf by the regulator to construct certain assets it would be, in our view, inequitable for the customers who remain to carry the cost of these investments. For this reason alone we would consider it to be an inappropriate course of action. One potential alternative is to require customers who withdraw from the grid to continue to meet the commitment made on their behalf. That is, to require them to continue paying for the distribution network services they were expected to use when the commitment was made even if they later choose not to use those services.

In our view this is a more equitable outcome as it prevents remaining customers from being forced to pay higher prices due to the choices of customers who withdraw.

In practice this could be implemented by requiring customers who withdraw from the grid to pay an exit fee when they choose to do so or to continue

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37 We understand that the AER has the ability to do this under the Rules, but that it has not done so to date.

38 There is an analogy between this argument and the argument that was recently put to the AEMC by the Major Energy Users that regulatory asset bases should be reviewed periodically. The AEMC determined that it should not make the rule partly because doing so would increase the risk to service providers and thus discourage investment. In the longer term, the AEMC considered that this disincentive would be detrimental to consumers.

paying for access after they have withdrawn. Neither approach is unprecedented as both have been used in the water sector.

Irrigation networks were funded on a volumetric (per ML) basis similar to the way electricity distribution networks are funded. As water trading was introduced in the 1990s to allow water to be used where it provided the highest value, some networks were stranded, or at risk of becoming stranded, as irrigators sold their water entitlements and abandoned, or reduced, irrigated farming.

Following a period of attempting to manage this by limiting trade between regions, the water sector has now reached the view that a more efficient approach is to unbundle tariffs so that water and network services are charged separately. In many cases, when an irrigator trades their water to another region, they either continue to pay for access to the network or pay an exit fee based on the revenue that the network would otherwise lose.

# 5 Conclusion

In summary, the key driver of DG uptake in the immediate term is likely to be the distortion that exists in retail electricity prices, as DG is often competitive with the full cost of electricity provision but not competitive with the truly variable component of this cost. However, it is entirely plausible that future technological advancements in DG and battery technologies will see DG technologies offer grid-standard reliability at costs that are competitive with the full (fixed and variable) cost of grid-supplied electricity. Such an outcome raises important and complex issues. These short and longer-term perspectives influence our answers to the esaa's six questions, which can be summarised as follows:

1. The most likely DG technology to be taken up in the immediate term remains solar PV. Other technologies such as gas fired micro turbines and fuel cells may become viable in future, but they have not yet 'arrived' in a commercial sense. Small wind turbines may have some impact, though this is likely to be limited by urban planning issues rather than technical difficulties. In any case, for the remainder of esaa's questions, the impact of DG on the electricity market relies on the output profile of the DG systems employed rather than the technology itself. From this perspective the key issue is whether the system is intermittent or at the operator's discretion and whether the intermittency can be predicted and relied upon.

2. The implications for the wholesale market are driven by the volume of DG uptake, which in turn is driven (at present, though not in the past) by the distortion in retail electricity prices. Without this and with the policy settings that have emerged recently in South Australia, Victoria and New South Wales there would be fewer DG systems in operation in the NEM, and therefore a lower level of intermittent, non-scheduled supply interacting with demand volatility to create wholesale market management issues. This has placed, and will continue to place, upward pressure on retail electricity prices.

3. Ideally DG systems would be adopted first where their contribution to the power system is greatest but with current policy settings there is little or no incentive for DG to be installed where it has most network value. Therefore, we expect that DG will continue to be scattered randomly across distribution networks, rather than where it truly avoids network costs. When comparing across distribution networks, there may be some tendency for solar PV to be taken up more rapidly in regions where insolation is stronger and less where it is weaker, but this incentive is reduced as the capital cost of DG systems falls. Rather, overall, the key driver is likely to be the variable component of retail electricity costs,

comprising primarily the variable component of network tariffs and wholesale energy costs.

4. The impact DG would have on customers is heavily dependent on the structure of network tariffs and policy settings. Under the status quo, DG allows customers who install it to transfer most of the burden of paying for network services to customers without DG. There is no relationship between the size of this transfer and any change in the cost of supplying those customers. The transfer from DG customers to non-DG customers will need to be arrested to make the system sustainable. One option to reweight network tariffs, and therefore retail electricity prices, is to increase the fixed (supply) charge and thus increasing their alignment with the underlying electricity supply cost structure.
5. If DG costs fall to the point where DG can compete with grid reliability at the full (fixed and variable) cost of electricity supply, a rapid uptake of DG systems may continue (or begin again) notwithstanding the reweighted tariffs. This would lead to an inefficient, and undesirable, duplication of resources.
6. The exit of customers from the grid leads to higher prices for those that remain is likely to be unsustainable. The increasing prices for remaining customers would intensify their incentive to take-up DG, exacerbating the problem. Importantly, if such a large-scale move to islanding of electricity consumers would likely impose higher aggregate electricity supply costs on society, as the cost of the network infrastructure that is bypassed is sunk, whereas future investments in DG systems can be avoided. Some pricing or regulatory response to the potential islanding of electricity consumers is warranted.

# Appendix A Effect of DG on customer bills

The recent rapid uptake of DG has had a significant impact on the retail price of electricity or, perhaps more accurately, the bills paid by electricity customers, particularly small customers.

This is largely due to the way that electricity prices are structured and that fact that, in large part, electricity bills recover the cost of providing network services, which is largely fixed, using a price that is variable. This creates an inefficiency in electricity prices generally and provides a much greater incentive to install DG than is efficient.

To illustrate, consider two hypothetical electricity customers in neighbouring houses. Both houses are identical and contain exactly the same appliances except that Customer 2's house has a larger air conditioner than Customer 1.[39]

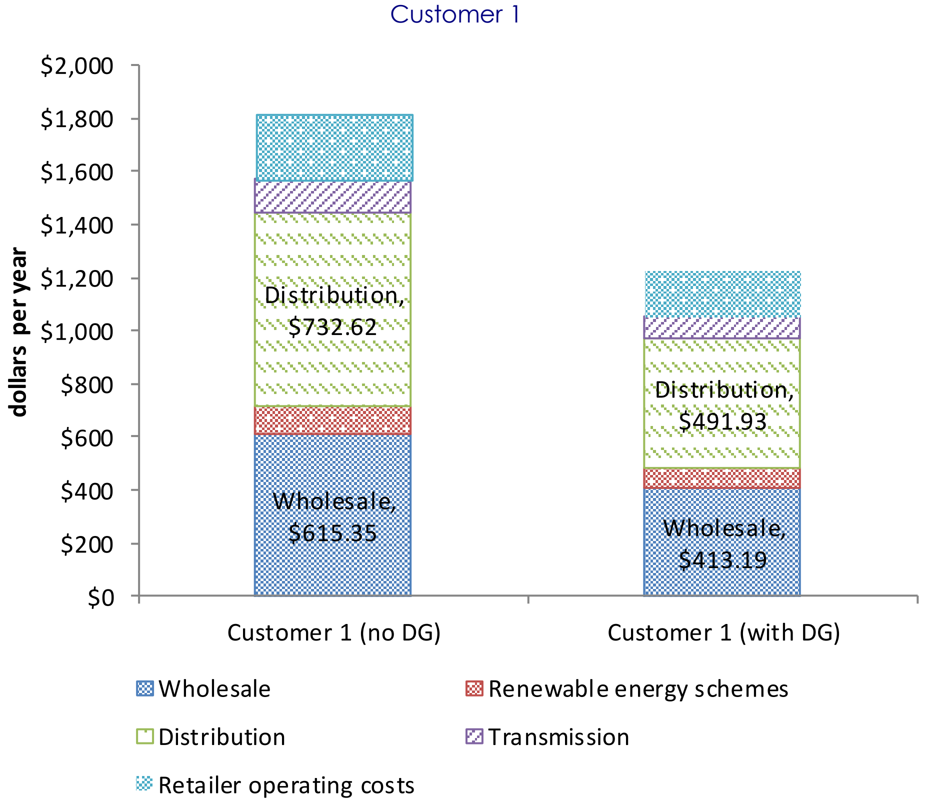
Customer 1 lives in their house full time. However, Customer 2 uses their house as a summer house, so it is occupied only two months of the year, though this includes times of system maximum demand.

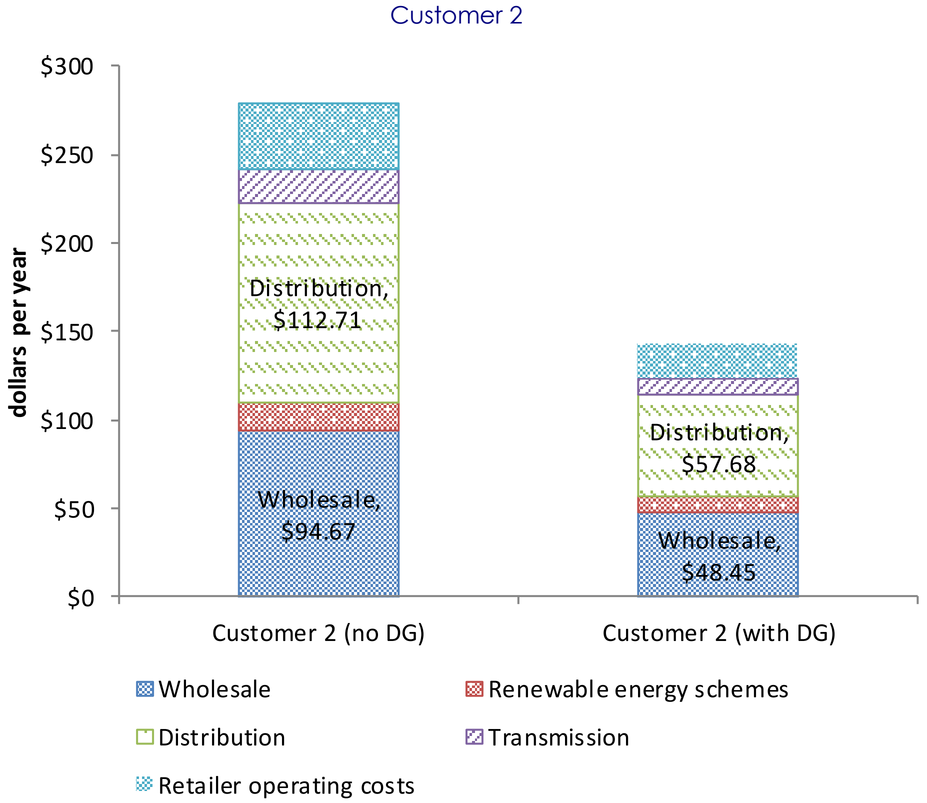
Due to the large air conditioner, Customer 2's demand at the time of peak demand on the network is higher than customer 1's demand at that time. Therefore, the cost of supplying distribution services to customer 2 is greater than the cost of supplying the same services to customer 1. This is because the distribution network must be 'sized' larger to accommodate customer 2's air conditioner.

However, customer 1 uses 6,500 kWh of electricity per year, while customer 2 uses 1,000 kWh per year. Therefore, customer 2 would pay less for electricity each year. Indicative bills for each individual bills would be as shown in Figure A1.

[39] Either both customers have air conditioners, but Customer 2's is larger, or Customer 2 has air conditioning but Customer 1 does not.

Figure A1 **Illustrative annual electricity bills for customers 1 and 2**



The bills illustrated in Figure A1 are broken down into the cost components of supplying electricity. They show that the distribution network cost component of a typical retail electricity bill is approximately 40 per cent and the wholesale energy component is approximately 30 per cent. The remainder is made up of other components including transmission, retailer operating costs and the cost of various 'green schemes (which vary from state to state).

Figure A1 shows that the contribution the two customers make to the cost of providing network services does not reflect the cost of providing them. With or without the DG systems, customer 2's impact on network costs is greater because their demand at peak times is higher. However, customer 1 pays substantially more for network services than customer 2. That is, the network component of Customer 2's bill (approximately $130) is less than one sixth of the network component of Customer 1's bill (approximately $850).

These amounts reflect each customer's average energy use over the year, which is unrelated to the cost of supplying them with distribution network services.

This is the inefficiency in the current approach to electricity network pricing. Retail electricity prices do not reflect the cost of supplying electricity.

Figure A1 also shows part of the incentive both customers face to install a DG system.

If Customer 1 installed a 2.5 kW PV system, we estimate that it would typically generate around 3,000 kWh of electricity each year, approximately triple their total consumption. However, due to timing, we estimate that they would use approximately 2,200 kWh of the electricity they generate on site, exporting approximately 850 kWh to the grid. Their annual electricity bill would be:

- $1,820 without their solar system, of which approximately $730 is for distribution network services
- $1,220 with their solar system, of which approximately $240 is for distribution network services

If it was Customer 2's that installed the PV system we estimate that they would export around 85 per cent of that output, thus using only less than 500kWh of the electricity they generate themselves.

Given our assumption regarding retail electricity prices, Customer 2's electricity bill, and their contribution to the cost of providing distribution network services, would be:

- $280 without their solar system, of which approximately $113 is for distribution network services
- $143 with their solar system, of which approximately $58 is for distribution network services

Therefore, by installing their PV system, Customer 1 obtains a saving of approximately one third. Customer 2 obtains a saving in their electricity bill of almost 50 per cent.

In addition to these savings, the customers may also receive a payment for the electricity they export to the grid. Depending on details such as which state they live in and when they installed their system, Customer 1's payment would range from approximately $75 to almost $2,000. With a 'midpoint' 44c/kWh net metered feed in payment they would receive $363 per annum. Customer 2's payment would range from approximately $200 per year to almost $2,000. [40] If they are eligible for a 'mid point' 44 cent per kWh net metered feed in payment, customer 2 would receive almost $1,100 per year.

Assuming a 'mid point' feed in payment, both customers would receive a combined saving and payment of approximately $1,000 each year due to their DG system.

This payment has two main impacts.

The first, and most significant impact, is that it *reallocates* network costs.

In the above example, part of the benefit to each customer was that they avoided buying electricity they generate and use themselves. In doing this they avoided not only the energy component of that price, but also the network component.

Given that the cost of providing network services is fixed, when one customer pays less for it, another must pay more. Therefore, the saving each customer made by avoiding the cost of providing them with distribution network services must be paid by other customers. In the above example, this means that other customers fund payments of approximately:

- $240 per annum for customer 1
- $55 per annum for customer 2

These payments are essentially wealth transfers from all customers to customers with DG systems. They cannot be justified on the basis of efficiency because they are not related to any change in the cost of providing network services to these customers.

The second impact of the payment is that it *overcompensates* DG operators for the value they provide.

[40] If both customers were eligible for the original New South Wales 66c/kWh gross metered FiT they would both receive the same payment regardless of their different 'on site' usage.

The payment could be thought of as relating entirely to the energy exported from the DG system to the grid. In this case, it amounts to approximately $500/MWh for customer 2 and more than $1,000/MWh for customer 1.

By comparison, in work for jurisdictional regulators we have previously estimated the wholesale value of electricity generated by PV systems to be in the order of 10 c/kWh.

Even if it is assumed that the customers receive no FiT payment for the electricity they export, the value Customer 1 receives is approximately $700 per MWh, well in excess of the wholesale value of the electricity. Customer 2 receives less value in this case because they use less electricity initially and thus have a smaller bill to avoid. This highlights the perverse incentive enshrined in these payments.

It is also possible to think of the payment the customers receive as relating, at least partly, to the network value their DG systems provide. It is reasonable to expect that their demand when system demand peaks will be less with the DG system that it would be without it, though it is difficult to estimate the size of this effect.

However, there is no way to link the current reduction in the amount Customer 1 pays for distribution network services with any change in the current cost of providing them. The customers might live in an area where the distribution network is near capacity. If they do, their choice to install DG might have an impact on deferring the augmentation of the network by causing demand growth in their area to be slower than it may otherwise have been.

On the other hand, most customers live in areas where the network is not constrained. As discussed in section 4.1, the incentives to install DG make no distinction between areas where the network value is high and areas where it is low. Therefore, the customers' choices to install DG systems are likely to have little or no impact at all on the cost of supplying them with distribution network services.

The result of the customers' choice to install DG is that other customers experience a collective increase in bills notwithstanding that there has been no apparent benefit associated with this bill increase. In this example, the impact may seem modest. The bill increase is about $2,000 (or about $750 if the FiT payment is disregarded) and there are hundreds of thousands of electricity customers who share in paying it, which makes the incremental cost for any individual customer small.

However, as the penetration of DG rises, the number of customers avoiding payments increases and as the cost base remains the same but must be funded by the reducing pool of other customers, the payment that must be funded by other customers' increases. This of course will drive up the per unit charges of electricity and create even greater incentives for more of the remaining pool of customers to invest in DG and become Customer 1s thus reducing the other pool further – with the potential for investment and payments to spiral out of control.

The potential spiral in investment and costs suggests that the current per unit postage stamp pricing methodology for small customers is unlikely to be sustainable in the longer term, if the installation of DG expands significantly. AEMO has forecast installations to increase from less than 2,000 MW as at the end of 2012 to around 5,000 MW for the NEM alone by 2020 and then increase substantially further after that as rooftop solar costs are forecast to continue to fall.

# Appendix B Where DG is likely to be adopted by DNSPs

The role of a DNSP is to 'distribute' electricity from the transmission network to customers. Our expectation is that DNSPs will adopt DG where their incentive to do so is strongest.

Under the various regulatory regimes applying to them, DNSPs are incentivised to meet certain performance standards in the cheapest way possible. They are penalised if they don't meet those performance standards.

The regulatory regime allows for the possibility that DNSPs may achieve their targets using non-network solutions. Indeed this is explicitly contemplated by clause 6.6.3 of the National Electricity Rules, which provides for the AER to develop a demand management incentive scheme, which it has done in all NEM regions. In the recent Power of Choice review the AEMC recommended certain changes to enhance the incentives.[41]

DG is one of a range of solutions that DNSPs could use to achieve their performance targets and meet growing demand without increasing the size of their network.

However, as the Australian Energy Regulator has noted, those schemes are not the sole, or even the primary, source of funding for demand management expenditure. The primary source should, in the AER's view, be the DNSPs forecast operating and capital expenditure.[42]

This reflects the AER's view that DNSPs should automatically use non network solutions, including DG, to meet demand for electricity when it is cheaper to do so than to extend the network in question. DNSPs are free to use non network alternatives to meeting their performance targets and are incentivised to do so when it is the lowest cost approach available.

Therefore, the future use of DG as a non-network solution depends on the cost of DG and other alternatives for supplying electricity demand, both network and non-network alternatives. It is possible that situations may arise where a DNSP forms the view that it would be more efficient to install DG in a particular area to meet demand than to install additional network

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41 See AEMC, "Power of Choice review – giving consumers options in the way they use electricity" Final report, recommendations 18 and 20 in particular and chapter 7 in general.

42 Australian Energy Regulator, "Demand Management Incentive Scheme for QLD and SA", p. 3 July 2008, available at www.aer.gov.au.

infrastructure.[43] Conceptually, this seems most likely to occur in areas where there is a significant, growing load far from others.

There are some examples of this in place already, such as the diesel generators on Kangaroo Island. Those generators were installed as an alternative to installing a second undersea cable to link Kangaroo Island to mainland South Australia.

The generators on Kangaroo Island are used for backup supply to support the distribution network. While clearly they supply energy when the connection to the mainland is interrupted, they are not intended to replace electricity bought from the wholesale electricity market or to disconnect Kangaroo Island from the grid under normal circumstances.

At this stage, this appears to be the most likely way that DNSPs would install DG. In particular, it seems unlikely that a DNSP would have an incentive to use DG to disconnect an existing group of customers from the grid or for customers in growth areas located close to the grid. Our expectation is that the cost of doing this with the necessary level of reliability would be prohibitive.

It is likely that customers located remotely from the grid would be most efficiently served using entirely islanded grids with local generators as is currently the case in remote areas of Western Australia, South Australia and the Northern Territory. However, these are special cases.

[43] The DNSP would also need to persuade the AER that this was the case through the regulatory process.

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